BEFORE THE PUBLIC UTILITIES COMMISSION OF THE

STATE OF HAWAII

In the Matter of PUBLIC UTILITIES COMMISSION Instituting a Proceeding to Investigate Performance-Based Regulation.	DOCKET NO. 2018-0088

ULUPONO INITIATIVE LLC'S SECOND PROPOSAL UPDATE

AND

CERTIFICATE OF SERVICE

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Ulupono Initiative LLC ("Ulupono"), by and through Murray Clay, its President, and its attorneys Schlack Ito, A Limited Liability Law Company, and pursuant to the Commission's Order No. 36388 Convening Phase 2 and Establishing a Procedural Schedule filed June 26, 2019 ("Order No. 36388"), hereby files its second proposal update ("Second Proposal Update") concerning the performance-based regulation ("PBR") mechanisms and issues identified in Decision and Order No. 36326 filed May 23, 2019 ("D&O 36326").[1]

[1] Ulupono's Second Proposal Update is timely filed on or before the due date of May 13, 2020 set forth in the Commission's "Hawaii PUC PBR Proceeding – Phase 2 Working Group Meeting #1" (Aug. 21, 2019). *Id.* at 3; *see also* "Performance-Based Regulation Proceeding: Phase 2 Workshop A" (Aug. 7, 2019) at 28; "Proceeding to Investigate Performance-Based Regulation: Phase 2 Workshop A Summary Notes" (Aug. 7, 2019) at 42; Order No. 36388 at 13, 16, 22 (Parties' second proposal updates to be due in May 2020).

EXECUTIVE SUMMARY[2]

A. Multi-year Rate Plan ("MRP").

PBR Review, rather than a formal rate case, should be undertaken at the conclusion of the initial or any subsequent five-year MRP period. The purpose of formal PBR Review would be to diagnose issues and adjust PBR mechanisms. PBR Review would be mandatory any time a credit rating downgrade has occurred, including at the end of a five-year MRP period; when triggered by the proposed PBR Review score; and any time the Commission deems a credit rating downgrade to be imminent or highly likely.

B. X-Factor.

Ulupono continues to support an X-Factor of zero. The PEG Response[3] and subsequent updates in the Working Group process do not justify a negative X-Factor. The peer group utilities are not subject to PBR and thus exhibit the capital expenditure bias and related inefficiencies. They also recover major project capital expenditures through their respective revenue adjustment mechanisms, rather than through a mechanism such as the Major Project Interim Recovery adjustment. Relatedly, Ulupono supports a consumer dividend factor in an amount equivalent to 22 basis points or, in the alternative, an amount equivalent to two times the avoided regulatory lag, as proposed by the Consumer Advocate.[4]

C. Z-Factor.

The Z-Factor should be available only for hurricanes and other natural disasters or pandemics, changes in federal law (e.g., tax law), and other exogenous events. It should not be

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[2] *See* Commission Staff, Hawaii PUC PBR Proceeding – Phase 2 RWG Meeting – Phase 2 (April 22, 2020) at "May Expectations" slide (second proposal updates to include two-page executive summary).

[3] Pacific Economics Group Research, LLC, "Response to Staff Discussion on the Revenue Cap Index" (March 8, 2019) ("PEG Response").

[4] State of Hawaii Department of Commerce and Consumer Affairs, Division of Consumer Advocacy ("Consumer Advocate").

used in response to an actual or imminent credit rating downgrade resulting from PBR mechanisms.

D. Earnings Sharing Mechanism ("ESM").

Ulupono's proposed ESM is intended to protect the utility's financial integrity and safeguard customers from excessive utility compensation. For reverse sharing, the 90% level of sharing back to the utility should be based on the return on equity ("ROE") level at which there appears to be a credit rating risk. Ulupono's proposed ESM reduces the volatility of ROE, which should support the utility's credit rating and protect utility returns within a reasonable range. The ESM should operate in conjunction with a cost of capital adjustment.

E. Major Project Interim Recovery ("MPIR").

The MPIR Guidelines should be clarified to allow recovery for new service area expansions. Contracts for non-capital expenses, including grid services and non-wires alternatives ("NWA") for projects that meet eligibility criteria should also be allowed.

F. Performance Incentive Mechanisms ("PIM") and Shared Savings Mechanisms ("SSM").

Ulupono offers three PIMs focused on acceleration of Renewable Portfolio Standard ("RPS")[5] achievement ("RPS-A"), the reduction of greenhouse gas ("GHG") emissions, and the electrification of transportation ("EoT"). All three PIMs achieve multiple priority outcomes and their financial impact is protective of the utility's financial integrity. Ulupono similarly supports SSMs for competitively-procured generation and grid services and NWAs. These PIMs and SSMs enable PBR to incentivize transformational change in Hawaii's energy and regulatory landscape.

[5] Chapter 269, Hawaii Revised Statutes, Part V, "Renewable Portfolio Standards" ("RPS law").

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List of Attachments and Exhibits

I. MULTI-YEAR RATE PLAN

In this Second Proposal Update, Ulupono refines and reaffirms its prior proposals concerning the five-year MRP period and the scope of Commission regulatory review at the end of the period.

A. MRP Period Should be Five Years.

Ulupono continues to support establishment of a five-year MRP as a foundational aspect of its proposals concerning the Annual Revenue Adjustment ("ARA"). This position in support of a five-year MRP period is consistent with D&O 36326, pursuant to which Phase 2 is to examine a five-year MRP.[6]

B. No Rate Cases Following Five-Year MRP Periods.

Similar to its continued support for a five-year MRP, Ulupono also supports and views as foundational the establishment of a PBR framework that does not contemplate or provide for a traditional rate case proceeding based on cost of service regulation ("COSR") principles ("rate case") upon the conclusion of the initial or any subsequent five-year MRP period.

Ulupono's position is consistent with the Commission's recent order terminating Hawaiian Electric's[7] mandatory triennial rate case cycle.[8] In Order No. 37119, the Commission explained that the PBR framework under consideration in this proceeding contemplates replacement of the mandatory triennial rate case cycle with an ARA combined with a five-year MRP.[9] The rationale underlying termination of the rate case cycle in Order No. 37119 is

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[6] *Id.* at 26.

[7] Hawaiian Electric Company, Inc. ("HECO"), Hawaii Electric Light Company, Inc. ("HELCO"), and Maui Electric Company, Limited ("MECO") (collectively, "Hawaiian Electric" or "Company").

[8] *See* Order No. 37119 Terminating Hawaiian Electric's Mandatory Triennial Rate Case Cycle filed April 29, 2020 (Docket No. 2008-0274) ("Order No. 37119).

[9] Order No. 37119 at 4.

consistent with Ulupono's position that the PBR framework in this proceeding should effectively terminate recourse to rate cases upon the conclusion of a five-year MRP period.

Ulupono has set forth its position on this issue, which is consistent with Order No. 37119, in its prior submissions.[10] Importantly, implementation of a robust earnings sharing mechanism ("ESM"), such as the ESM supported by Ulupono in this proceeding, should safeguard Hawaiian Electric's credit rating and general financial integrity. The ESM (in combination with a five-year MRP, the ARA taking effect on January 1, and PBR Review in place of rate cases) should also afford Hawaiian Electric added flexibility to avoid regulatory lag and to greatly reduce time and resources devoted to the regulatory process. Including a future traditional rate case in PBR is also very likely to result in Hawaiian Electric focusing on higher cost initiatives to justify higher revenues, and to otherwise not take advantage of cost-saving measures during the MRP period, contrary to PBR cost control incentives.

In addition, a rate case also could result in utility expectations and actions during the MRP which may be contrary to or undermine successful PBR implementation[11] and fail to break the direct link between revenues and capital investments, as is required by statute.[12] As explained in Ulupono's First Proposal Update, reverting to a rate case would not be consistent with the fundamental purpose of PBR, which is to align Hawaiian Electric's incentives to achieve energy policy objectives.[13] These objections to establishing a PBR framework that provides for rate cases address fundamental concerns, reflecting the ability of rate cases to

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[10] *See, e.g.,* Ulupono Initiative LLC's First Proposal Update filed Jan. 15, 2020 ("First Proposal Update") at 7-8. *See also* Commission Staff, Hawaii PUC PBR Proceeding – Phase 2 PWG Meeting #6 Summary Notes (March 25, 2020) ("PWG Meeting #6 Summary Notes") at "Additional Guidance" ("PBR will continue to be the basis for determining utility revenues beyond the end of the initial MYRP. However, the Commission expects to review the PBR Framework before the end of the MYRP and will evaluate and make necessary changes.")

[11] *See, e.g.*, Division of Consumer Advocacy's Statement of Position on Staff Proposal for Updated Performance-Based Regulations filed March 8, 2019 (Docket No. 2018-0088) ("CA SOP") at 19-20.

[12] *See* Haw. Rev. Stat. § 269-16.1(a), codifying Act 5, 2018 Haw. Sess. Laws, Act 005; S.B. 2939 29th Leg. (Haw. 2018)) ("Act 5") (regulation must "break the direct link" between capital expenditures and utility revenues).

[13] First Proposal Update at 8.

hamper successful PBR implementation. Accordingly, Ulupono's position on this issue remains that the PBR framework should not incorporate or allow for rate cases and Ulupono's PBR mechanism proposals are premised on that conclusion.

C. PBR Review May be Necessary Under Limited Circumstances.

Although Ulupono opposes rate cases upon the conclusion of five-year MRP periods, as previously explained Ulupono supports consideration of formal PBR Review any time a credit rating downgrade has occurred, including at the end of a five-year MRP period, and any time the PBR Review score criteria (as discussed below) is met at the end of a five-year MRP period. In addition, Ulupono continues to propose that the Commission may initiate PBR Review any time it deems a credit rating downgrade to be imminent or highly likely.[14]

It should be emphasized that PBR Review would not be intended to function in a manner equivalent to that of a traditional rate case, but rather would provide an opportunity for the Commission and stakeholders to consider adjustments to improve the operation and implementation of the existing PBR mechanisms, consistent with the fundamental purpose of adopting PBR. Unlike a rate case, the purpose of a PBR Review would be to diagnose, evaluate and consider adjustments or modifications to ARA factors, PIMs and other PBR mechanisms.

A range of PBR mechanisms could be considered in PBR Review. For example, the ARA mechanisms subject to PBR Review could include the X-Factor amount, Z-Factor criteria, and consumer dividend factor. PBR Review could also examine ESM sharing breakpoints and percentages, MPIR criteria, and calibration of the reward and penalty amounts and breakpoints for PIMs. Importantly, PBR Review could also entail the Commission, on its own initiative, authorizing a limited, one-time increase in authorized revenues.

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[14] It should be noted that, as proposed by Ulupono, only the Commission and not Hawaiian Electric would be able to initiate PBR Review under these circumstances, i.e., when a credit rating downgrade imminent or highly likely.

D. PBR Review Score May Trigger PBR Review.

As noted above and as explained in Ulupono's First Proposal Update, one of the three circumstances under which PBR Review may be considered would be based on the determination of a PBR Review score.[15] Specifically, if the PBR Review score, as determined at the conclusion of a five-year MRP period, qualifies for PBR Review then such review would be undertaken at that time.

In essence, the PBR Review score is based on consideration of the magnitude, consistency and trends concerning deviations of Hawaiian Electric's earned ROE from the utility's authorized ROE. The proposed PBR Review score provides a means of quantifying an assessment of these underlying principles based on the functioning of the ESM. Ulupono submits that the magnitude, consistency, and trends in deviations of earned or realized ROE from authorized ROE are a reasonable proxy for whether PBR is working as intended. Modest deviations and occasional ESM sharing (whether to the customer or the utility) are to be expected, and only large and consistent deviations or increasingly problematic trends (for example, increasingly high or increasingly low ROE) should provide a reason to review and possibly modify PBR components pursuant to PBR Review.

As explained in the First Proposal Update, certain basic steps are employed to determine the PBR Review score.[16] Figure 1, below, "PBR Review Score," further illustrates the components and calculations necessary for determination of the PBR Review score.

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[15] *See* Ulupono First Proposal Update at 9-13.

[16] The following describes the basic steps in determining the PBR Review score, assuming an ESM with upside and downside sharing has been adopted under Ulupono's proposed ESM. This proposed ESM is illustrated in Exhibit A-2, "Impact of Earnings Sharing Mechanism," attached ("Exhibit A-2"), which has breakpoints at 2, 3, and 4 percentage points above and below authorized ROE. Each year a score is generated based on the level of post-ESM achieved ROE. For example, the score would be zero for the post-ESM ROE within the deadband, -1 for the post-ESM ROE within the first level of sharing below the deadband, -2 for the second level, and -3 for the third level. Similarly, for the post-ESM ROE above the deadband, the first level is a score of 1, then 2 for the second level of sharing, and then 3 for the third level. Thus, for each year a score is generated between -3 (90% sharing back to the

Fig. 1

"PBR Review Score"

Utility Historical Achieved Return on Equity and Authorized Return on Equity[17]											
HECO	ROE	Auth	Diff	**MECO**	ROE	Auth.	Diff	**HELCO**	ROE	Auth	Diff
2008	8.07	10.7	-2.63	2008	8.54	10.94	-2.4	2008	9.39	11.5	-2.11
2009	7.02	10.7	-3.68	2009	4.76	10.94	-6.18	2009	6.89	11.5	-4.61
2010	6.15	10	-3.85	2010	3.9	10.7	-6.8	2010	6.24	10.7	-4.46
2011	8.03	10	-1.97	2011	8.1	10.7	-2.6	2011	10.85	10.7	0.15
2012	10.7	10	0.7	2012	6.69	10	-3.31	2012	7.79	10	-2.21
2013	8.95	10	-1.05	2013	9.35	9	0.35	2013	7.46	10	-2.54
2014	9.85	10	-0.15	2014	9.47	9	0.47	2014	6.65	10	-3.35
2015	9.2	10	-0.8	2015	8.76	9	-0.24	2015	7.49	10	-2.51
2016	9.46	10	-0.54	2016	8.34	9	-0.66	2016	7.61	10	-2.39
2017	6.83	9.5	-2.67	2017	6.84	9	-2.16	2017	7.3	9.5	-2.2
2018	7.89	9.5	-1.61	2018	7.38	9	-1.62	2018	8.08	9.5	-1.42

Achieved Minus Authorized ROE			
Year	**HECO**	**MECO**	**HELCO**
2008	-2.63	-2.4	-2.11
2009	-3.68	-6.18	-4.61
2010	-3.85	-6.8	-4.46
2011	-1.97	-2.6	0.15
2012	0.7	-3.31	-2.21
2013	-1.05	0.35	-2.54
2014	-0.15	0.47	-3.35
2015	-0.8	-0.24	-2.51
2016	-0.54	-0.66	-2.39
2017	-2.67	-2.16	-2.2
2018	-1.61	-1.62	-1.42

Achieved Minus Authorized ROE (after ESM)			
Year	**HECO**	**MECO**	**HELCO**
2008	-2.473	-2.3	-2.083
2009	-3.09	-3.468	-3.311
2010	-3.175	-3.53	-3.296
2011	-1.97	-2.45	0.15
2012	0.7	-2.905	-2.158
2013	-1.05	0.35	-2.405
2014	-0.15	0.47	-2.925
2015	-0.8	-0.24	-2.383
2016	-0.54	-0.66	-2.293
2017	-2.503	-2.12	-2.15
2018	-1.61	-1.62	-1.42

ESM Breakpoints (relative to Authorized ROE)	-4	-3	-2	0	2	3	4

utility, or 5.5% post-ESM ROE and below, under Ulupono's proposed ESM) and positive 3 (90% sharing back to utility customer for a post-ESM ROE of 13.5% and higher, or 4% above the authorized ROE). At the end of the five-year MRP period, the individual scores for each of the five years are added together ("five-year score"). PBR Review would be triggered if the five-year score is -3 or less or 5 or greater.

[17] Achieved and Authorized ROE figures from Statement of Position of the Hawaiian Electric Companies filed March 8, 2019 (Docket No. 2018-0088). *See id.* at 14; Exhibit E at 13-14.

PBR Review score (based on Post-ESM ROE)	-3	-2	-1	0	1	2	3

PBR Review Score-Historical, pre-ESM			
Year	HECO	MECO	HELCO
2008	-1	-1	-1
2009	-2	-3	-3
2010	-2	-3	-3
2011	0	-1	0
2012	0	-2	-1
2013	0	0	-1
2014	0	0	-2
2015	0	0	-1
2016	0	0	-1
2017	-1	-1	-1
2018	0	0	0

PBR Review Score-Historical, after ESM			
Year	HECO	MECO	HELCO
2008	-1	-1	-1
2009	-2	-2	-2
2010	-2	-2	-2
2011	0	-1	0
2012	0	-1	-1
2013	0	0	-1
2014	0	0	-1
2015	0	0	-1
2016	0	0	-1
2017	-1	-1	-1
2018	0	0	0

PBR Review scoring is designed to allow Hawaiian Electric additional time to potentially earn above its authorized ROE before PBR Review modifies the existing PBR mechanisms. This is allowed through an asymmetric scoring structure which remains in place unless and until the utility earns an improved credit rating. At this time, the improved credit rating goals for Hawaiian Electric are proposed as at or above BBB+ for Fitch, Baa1 for Moody's and BBB+ for S&P. If and when all three of these credit rating goals are achieved, or one of the credit ratings is one or more rating grades above the foregoing three goals, then the plus 5 score criteria (which could trigger PBR Review) would be removed from consideration, in favor of symmetrical criteria (-3 or lower, or 3 or greater) for the five-year score to trigger a PBR Review. This asymmetric approach allows reasonable room for improvement in credit rating before PBR Review adjusts PBR mechanisms in a manner that would potentially make it more difficult for Hawaiian Electric to raise the score.

The proposed PBR Review scoring also takes into account volatility, or relatively large swings or changes in ROE as well as PBR scores during a five-year MRP period. For example, volatility concerns may trigger PBR Review if during the five-year MRP period there is (i) one year (or more than one year) when there is post-ESM ROE above the 90% upside sharing breakpoint, and (ii) one year (or more than one year) when there is post-ESM ROE below the 90% downside sharing breakpoint. These scores of -3 and 3 would normally offset each other when the five-year score is determined (by adding the five annual scores) and PBR Review would not be required. As proposed, however, PBR Review would be triggered under these circumstances to address the volatility between the top and bottom sharing breakpoints. Such extreme volatility may be a sign that some part of the PBR construct is not working as intended – making review both necessary and appropriate.

For this Second Proposal Update, Ulupono has prepared a slightly updated version of its "Proposed PBR Review" exhibit.[18] This exhibit depicts determination of the score on a forward-looking basis[19] and demonstrates how Ulupono's proposed PBR Review score, based on the post-ESM ROE, and a five-year sum of the PBR Review score, would indicate the need for PBR Review at the conclusion of a five-year MRP. For example, as shown in the exhibit a score of 4 in 2026 and 2 in 2031 would not trigger a PBR review, with the exception that for 2026 review could be triggered if the utility had previously realized the proposed credit

[18] *See* Exhibit A-1, "Proposed PBR Review" ("Exhibit A-1"), attached. Exhibit A-1 has been modified to reflect commencement of the five-year MRP period in 2021.

[19] It should be noted that Exhibit A-1 refers to "Automatic Review" in 2026 and 2031. This Automatic Review is not intended to refer to or function in an equivalent manner as a traditional COSR rate case. Rather, this reference is included solely based on the inherent inability to predict with reasonable certainty the outcome of PBR Review. PBR Review, should it occur in 2026 or at the conclusion of any other five-year MRP period, will diagnose issues and may result in adjustments to one or more PBR mechanisms. Rather than attempt to predict the outcome of any such PBR Review, Exhibit A-1 includes Automatic Review as a placeholder.

rating goals of BBB+, or equivalent, for all three credit rating agencies prior to the completion of the applicable five-year MRP.[20]

With the ESM applied annually, the PBR Review process at the end of a five-year MRP is sufficient to protect the utility's financial integrity. As shown in Figure 1, since 2008 there has not been a single achieved ROE for HECO, HELCO or MECO that would have resulted in a post-ESM ROE of less than 5.5% (assuming Ulupono's proposed ESM was applied to historic deviations between authorized and achieved ROEs).

Finally, for this Second Proposal Update comments on implementation of PBR Review scoring are offered. In essence, Ulupono suggests that the PBR score may be determined and applied similar to the ARA. This assumes the ARA is determined following the conclusion of the applicable calendar year and applied retroactively. Similar to the ARA, a preliminary PBR Review score can be determined prior to the conclusion of the applicable time period and then revised and subject to a retroactively-applied true-up after the period concludes. Thus, if the PBR Review score criteria indicates the need for PBR Review, this review would take place early in the first year of the new MRP with any changes applied retroactively to January 1 of the new five-year MRP period.

II. INFLATION FACTOR

The inflation factor requires little discussion insofar as Ulupono continues to support utilization of the Gross Domestic Product Price Index ("GDPPI") as an inflation index. Pursuant to D&O 36326, the inflation factor is described as the "[a]nnual change according to a published inflation index."[21] Ulupono supports utilization of GDPPI consistent with the

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[20] As previously noted, the improved credit rating goals are at or above BBB+ for Fitch, Baa1 for Moody's and BBB+ for S&P.
[21] *Id.* at 29, n. 32.

positions of other parties, including the Consumer Advocate, Hawaiian Electric and Blue Planet Foundation ("Blue Planet").[22]

III. X-FACTOR

For this Second Proposal Update, Ulupono reaffirms its support for an X-Factor of zero and offers other refinements to is critique of the negative X-Factor proposed by Hawaiian Electric. Pursuant to D&O 36326, during the MRP Hawaiian Electric's revenues will be determined by an ARA, in the form of an indexed revenue formula, in combination with PIMs and cost trackers.[23]

A. Ulupono Continues to Support an X-Factor of Zero.

For this Second Proposal Update, Ulupono reaffirms its support for an X-Factor of zero and provides additional comments for that position and against the negative X-Factor proposed by Hawaiian Electric. As explained in its First Proposal Update, Ulupono generally concurs with the rationale in support of an X-Factor of zero as stated by the Consumer Advocate in its Initial Proposal[24] and further developed in the Consumer Advocate's First Proposal Update.[25] Pursuant to D&O 36326, the X-Factor is described as the "[p]redetermined annual productivity factor."[26] In the HECO First Proposal Update, as well prior submissions, Hawaiian

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[22] *See, e.g.,* Updated Comprehensive Proposal of the Hawaiian Electric Companies filed Jan. 15, 2020 ("HECO First Proposal Update") at 4 (GDPPI as inflation factor); Division of Consumer Advocacy's First Proposal Update for Phase 2 filed Jan. 15, 2020 ("CA First Proposal Update") at 2 (same); Blue Planet Foundation's Initial Phase 2 Proposals filed Aug. 14, 2019 at 8 (same).
[23] *Id.* at 27-28.
[24] *See* Division of Consumer Advocacy's Initial Comprehensive Proposal for Phase 2 filed Aug. 14, 2019 ("CA Initial Proposal") at 10-13.
[25] *See* CA First Proposal Update at 11-20 (explaining that "[t]here has been no credible showing by any party in Phase 2 that an appropriate productivity input applicable to Hawaiian Electric is a non-zero value."
[26] *Id.* at 29, n. 32.

Electric argues the X-factor should be negative.[27] In support of its contention, Hawaiian Electric relies on the PEG Response.[28]

1. The PEG analyses are flawed.

For this Second Proposal Update, Ulupono reiterates its prior explanations of the flaws of the PEG Response as set forth in its First Proposal Update. As an initial matter, the PEG Response relies on a purported sample of forty-four vertically-integrated electric utilities ("VIEU"). The PEG Response, which was subsequently updated to include additional VIEUs, concludes that the X-Factor "must be negative if the hypothetical revenue cap indexes are to track historical VIEU [vertically-integrated electric utility] costs of base rate inputs on average."[29] The PEG Response cites to its Table 5, "U.S. VIEU Kahn X Factor Calculations" ("Table 5").[30] In an explanatory footnote, Table 5 states: "All values shown are an average of annual (logarithmic) growth rates of variables on a nationally-representative sample of 44 vertically integrated electric utilities."[31]

The PEG analyses are flawed because the VIEUs selected for the analysis are not subject to PBR focused on addressing the capital bias. Hawaiian Electric's First Proposal Update fails to establish that most or all of these forty-four utilities are subject to PBR mechanisms that "break the direct link between allowed revenues and investment levels"[32] or are otherwise meaningfully similar to the potential PBR mechanisms under consideration in this proceeding. To the contrary, assuming most if not all the referenced VIEUs remain regulated under COSR, it should be assumed they have an ongoing financial incentive to increase rate base

[27] *See* HECO First Proposal Update at 25-31; Hawaiian Electric Companies Statement of Position filed March 8, 2019 (Docket No. 2018-0088) ("Hawaiian Electric SOP") at 18, 26, Exhibit B.
[28] The PEG Response is attached as Exhibit B to the HECO SOP.
[29] HECO SOP, Exhibit B at 12.
[30] *Id.* at 13.
[31] *Id.* (emphasis added).
[32] Haw. Rev. Stat. § 269-16.1(a).

pursuant to the widely-confirmed COSR capital expenditure bias. In addition to the capital expenditure bias, these VIEUs are subject to COSR which typically passes higher costs to utility customers through rate cases. Thus, to the extent these other VIEUs are not subject to PBR that is relatively similar to the PBR framework contemplated in this proceeding, their value in providing an evidentiary basis for adopting a negative X-Factor value is extremely limited.[33]

The PEG analyses are also flawed to the extent the stream of revenues relied upon in the PEG Response to calculate X-Factor included revenues from major projects. Hawaiian Electric may recover major project costs through the MPIR adjustment. There is no indication, however, that the VIEUs in the PEG analyses utilize a similar regulatory construct. Rather, there appears to be a form of double-counting to the extent these VIEUs do not have a dedicated adjustment mechanism for major project costs.

The methodological challenges inherent in the approach taken by the PEG Response are further suggested by a subsequent corrective analysis submitted by the utility. The utility justified its proposed negative X-Factor in this proceeding based primarily on the methodology and results set forth in the PEG Response. The results of the PEG Response were subsequently modified, however, based on further review and analysis. Instead of -1.46%, PEG now proposes an X-Factor of -1.32%, or, in the alternative, -.0.99%.[34] Although corrections and adjustments are to be expected, the magnitude of these adjustments appear to illustrate the methodological challenges associated with accurately deriving an X-Factor.

Finally, it should be emphasized that an X-Factor of -1.32 based on other jurisdictions is fundamentally at odds with Act 5, which contemplates transformative regulatory

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[33] For clarity, at this time Ulupono reserves judgment as to whether the PEG Response analysis conclusively supports a negative X-Factor even for VIEUs with an established capital bias under traditional COSR.
[34] *See, e.g.,* Hawaiian Electric, "PBR Financial Scenarios" submitted for the RWG Working Group Meeting on April 22, 2020 at 4.

results not comparable to or in keeping with regulation in other jurisdictions.[35] The Commission has repeatedly affirmed its approach to PBR as including fundamental or transformational change.[36] The proposal to base Hawaii's X-Factor on non-Hawaii jurisdictions that are not engaged in such change, and are not evolving toward more transformational PBR mechanisms, strongly undercuts any support the PEG Response (even as amended) may provide to adoption of a negative X-Factor.[37]

2. An X-Factor of zero assumes robust competitive procurement.

Ulupono's support for an X-Factor of zero continues to be conditioned in part on the Commission ensuring growth in competitive procurement of generation resources and grid services. Ulupono submits that, from a customer bill impacts perspective, the X-Factor is relatively less important to the customer to the extent it is outweighed by the benefits from competitively-procured resources. For example, as fossil fuel plants are retired and replaced by competitively-procured renewable generation, NWAs and grid services, the X-Factor – and especially the alleged necessity for a negative X-Factor – becomes relatively less important. Thus, Ulupono supports continued growth in the relative proportion of competitively procured generation resources and grid services, including NWA.[38]

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[35] Act 5 at § 1.

[36] *See, e.g.,* Order No. 35411 Instituting a Proceeding to Investigate Performance-Based Regulation" filed April 18, 2018 ("Order No. 35411") at 5 (PBR may result over time in "more fundamental changes to the regulatory framework"); D&O 36326 at 3 (Hawaii's electric sector in period of "dramatic transformation" necessitating Hawaii's regulatory framework to "evolve and adapt to the changing system.").

[37] An X-Factor of zero would also be directionally a strong improvement from the cost increases typical of COSR as reflected in Hawaiian Electric's proposed X-Factors of -1.32% or -0.99%.

[38] Relatedly, with regard to future procurements of renewable generation Ulupono generally supports the Commission allowing contracting between the utility and independent power producers ("IPP") that allows IPPs to sell curtailed energy to third parties or utilize such curtailed energy to produce hydrogen, with the latter providing a means to generate firm power. In general, under the RPS-A PIM the utility should be incentivized to minimize curtailment.

3. Negative X-Factor not supported by broader regulatory analysis.

A broader analysis reinforcing the concern over misplaced reliance on the PEG Report, as amended, and non-PBR VIEUs follows from a more general concern and critique of developing and relying on an X-Factor in the current regulatory context.

One of the core components of PBR is the use of a price index for adjusting revenue requirements or rates, which tracks an industry-wide measure of price inflation, combined with an X-Factor, which is intended to quantify the degree to which the regulated sector can be expected to experience greater or lesser levels of inflation than the economy overall. The X-Factor reflects the combined impact of the relative changes in input prices and total factor productivity impacting the regulated sector versus the rest of the economy. For example, to the extent the pace of total factor productivity growth is greater than the increase in input prices facing the regulated sector, compared to the economy overall, the X-Factor should be greater than zero. That is, prices in the regulated sector should fall relative to prices in the broader economy.[39]

Several challenges have been identified with regard to establishing an X-Factor for PBR in Hawaii. For example, it will be difficult to develop a truly comparable peer group for establishing the X-Factor based on input prices. Such prices faced by regulated electric utilities that would serve as a natural peer group, for example, do not reflect the higher transportation costs and other factor prices faced by Hawaii utilities, and thus also do not reflect the resulting substitution effects in utility operating behavior. As a result, producer price indices for the utility sector would be expected to behave significantly differently on the U.S. continent as compared to in Hawaii.

[39] *See* Bernstein, Jeremy and David Sappington, "How to determine the X in RPI-X regulation: a user's guide," Telecommunications Policy 24, 2000.

More importantly, total factor productivity would be expected to be higher and improve at a faster pace for electric utilities operating in a PBR regime than under traditional cost of service regulation. Only a handful of U.S. utilities operate under PBR, however, and those that do confront very different sets of regulatory incentives. Therefore, applying a benchmark based on a peer group of (at least theoretically) less efficient cost of service utilities is a problematic basis of comparison for Hawaii utilities regulated under a PBR regime.

More generally, the high degree of heterogeneity of assets and operating conditions makes it very challenging to develop robust benchmarks for electric utilities. This is especially true for VIEUs such as those in Hawaii, where myriad differences – geographic, load, legacy assets, system topology, regional fuel prices, regulatory regimes – make apples-to-apples comparison of factor productivity difficult.[40] The literature also emphasizes the importance of applying very different benchmarking techniques to electric distribution versus transmission assets, further complicating the exercise for undertaking a highly rigorous benchmarking effort for Hawaii.[41] Such benchmarking efforts themselves may become a source of delay in implementing a new PBR framework, and such delays should be avoided.

In addition, from the standpoint of creating an incentive to improve overall efficiency the specific level of the X-Factor is irrelevant. Under effectively fixed rates or revenue requirements, utilities face a uniform incentive to minimize costs – subject to performance conditions and other performance incentive mechanisms – regardless of the X-

[40] *See* Llorca, Manuel, Luis Orea, and Michael Pollitt, "Using the latent class approach to cluster firms in benchmarking: An application to the US transmission industry," Operations Research Perspectives 1, 2014 for a discussion of the challenges in utility benchmarking electric utilities, even using sophisticated econometric techniques.

[41] *See* Janda, Karel and Stepan Krska, "Benchmarking Methods in the Regulation of Electricity Distribution System Operators," Charles University in Prague, October 2014. Note that these benchmarking of generation systems for the purposes of estimating an X-Factor is not practiced in Europe given its regulatory regime.

Factor. The X-Factor simply determines the allocation of costs between ratepayers and the utility.[42]

Given these inherent uncertainties, Ulupono's position continues to be employing a falsely precise or large (negative or positive) value for the X-Factor, such as Hawaiian Electric's proposed X-Factor of -1.32% or 0.99%, is not advisable. It may create a perception of false precision, or result in devoting an excessive level of resources to the task of determining the X-Factor, or may even create opportunities for unproductive gaming of the X-Factor setting analysis. Setting the X-Factor to a very low absolute value (like zero), as a starting position, has merit as well as the advantage of simplicity. It would also be consistent with FERC rulings on the X-Factor applied to indices for (distribution) utilities.[43]

IV. CONSUMER DIVIDEND

As an update for this submission, Ulupono is open to supporting the Consumer Advocate's proposed consumer dividend of one-time bill credits totaling approximately $26.5 million (i.e., two times the value of the regulatory lag) across the three utilities (i.e., HECO, HELCO and MECO), which would be funded in part by utility customers through acceleration of ARA increases to January 1 at inception of a five-year MRP period.[44]

Ulupono also continues to support the consumer dividend of 22 basis points[45] or otherwise in the range of approximately 20-30 basis points of the utility's authorized ROE – if an annual consumer dividend is preferred, rather than a one-time consumer dividend.[46] Ulupono's

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[42] *See* International Benchmarking of Electricity Transmission by Regulators: Theory and Practice, Haney, Aoife Brophy and Michael G. Pollitt, EPRG Working Papers, Cambridge Working Paper in Economics, CWPE 1254 & EPRG 1226, November 2012.
[43] *See* Lowry, M.N., J. Deason, M. Makos, L. Schwartz, "State Performance-Based Regulation Using Multiyear Rate Plans for U.S. Electric Utilities," LBNL, July 2017.
[44] CA First Proposal Update at 21-22.
[45] *See* First Proposal Update at 23.
[46] *See* HECO First Proposal Update at 31-32 (if consumer dividend is adopted then "ARA should include consumer Dividend Factor of 0.22% in the ARA Formula.").

financial model, the Regulatory Innovation Simulation Tool ("RIST"), utilizes 22 basis points for the consumer dividend factor,[47] which was proposed in the Ulupono First Proposal Update.[48]

It is noted that pursuant to D&O 36326, the consumer dividend factor is intended as a 'stretch factor' or reduction in allowed revenues'[49] which is expected to "help ensure that 'day one' savings for utility customers are realized."[50] Ulupono agrees with this general intent and thus supports either of the foregoing two approaches to setting the consumer dividend amount.

V. Z-FACTOR

Ulupono offers the following refinements to its position on the Z-Factor. Pursuant to D&O 36326, the Z-Factor is described as the "[f]actor applied (ex post) to account for <u>exceptional circumstances not in the utility's direct control</u> (e.g., tax law changes)."[51] The Z-Factor is a factor applied to account for "exceptional circumstances" not in utility's direct control or "uncontrolled exogenous events," such as major tax law changes, that affect Hawaiian Electric's costs.[52] Z-Factor revenue adjustments could be positive or negative.[53]

A. Recovery for Only Exogenous Events Beyond Utility Control.

Ulupono continues to support availability of the Z-Factor only for truly exogenous events such as hurricanes (as well as tsunamis, volcanic eruptions, or other natural disasters) and pandemics, changes in federal law (e.g., tax law) and other similar types of

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[47] *See* First Proposal Update, Exhibit 2 (Fig. 11), "Revenue Breakdown: Ulupono Initiative First Proposal Update v. Status Quo" at n. 3 (ARA utilizes Consumer Dividend of 0.22%).
[48] A copy the version of the RIST utilized by Ulupono to generate the modeling results presented in this submission has been made available to the Commission and parties in conjunction with the filing of this Second Updated Proposal. *See* Exhibit D-1, attached. Relatively recent updates to the RIST are summarized in Exhibit D-3, "Recent RIST Updates: May 2020."
[49] Ulupono First Proposal Update at 29, n. 32.
[50] *Id.* at 31.
[51] *Id.* at 29, n. 32 (emphasis added).
[52] Staff Proposal for Updated Performance-Based Regulations filed February 7, 2019 (Docket No. 2018-0088) ("Staff Proposal") at 26-27.
[53] *Id.* at 27.

unforeseen and uncontrollable events.[54] In particular, the Z-Factor should not be utilized in response to an actual or imminent credit rating downgrade resulting from the implementation of PBR mechanisms – such circumstances should be addressed through PBR Review, as discussed above.

B. No Recovery for Inadequate Planning or Maintenance.

The availability of cost recovery under the Z-Factor, for losses due to hurricanes (as well as tsunamis, volcanic eruptions or other natural disasters) should be limited or not available if costs are incurred due to inadequate planning or maintenance by Hawaiian Electric. With regard to planning, if properly executed the Integrated Grid Planning ("IGP") process[55] should result in energy resource planning that sufficiently plans and accounts for such impacts to the grid. The Z-Factor should not serve as a substitute for proper IGP planning – assuming the IGP process does not foreclose necessary reliance on MPIR adjustments, or some other similar means to allow cost recovery for resilience and other related large-scale programs. In essence, the Commission should condition Z-Factor availability upon demonstration that the utilities properly planned to avoid or mitigate potential losses from hurricanes or other natural disasters.

Similarly, the Z-Factor should not be available if costs are incurred due to inadequate operations and maintenance. The cost impacts of hurricanes or major storms, for example, may be exacerbated by inadequate vegetation management. Prolonged failure to implement vegetation management sufficient to minimize impacts from hurricanes or major storms should not be rewarded through Z-Factor recovery, especially insofar as reduced or deferred utility operations and maintenance expenses will result in higher earnings under fixed

[54] Ulupono First Proposal Update at 20-23.

[55] *See* Hawaiian Electric, "Planning Hawaii's Grid for Future Generations: Integrated Grid Planning Report" filed July 13, 2018 (Docket No. 2018-0165); Hawaiian Electric, "Planning Hawaii's Grid for Future Generations: Integrated Grid Planning Workplan" filed Dec. 14, 2018 (Docket No. 2018-0165).

revenues. Doing so may create a perverse incentive for the utilities to reduce vegetation management activities based on an expectation that future storm impact costs may be recovered through the Z-Factor. A similar dynamic may occur with regard to prudent operation and maintenance practices for generation facilities.

C. Recovery Over Time May be Appropriate.

Under certain circumstances, it may be necessary or advisable for the Commission to allow utility recovery of Z-Factor amounts over a relatively extended time period. The primary purpose of not allowing recovery at one time would be to protect otherwise disadvantaged utility customers. This assumes impacts to diverse groups of utility customers from the natural disaster or emergency that triggers and qualifies for Z-Factor recovery.[56] Specifically, if large numbers of customers are unable to pay their electric bills, the burden of Z-Factor recovery amounts may fall to remaining customers. To avoid this potentially adverse outcome, it may be appropriate to authorize Z-Factor recovery over an extended time period.

The occurrence of a pandemic similar to Covid-19 may illustrate the importance of extending Z-Factor recovery over time, especially when the Z-Factor event results in an economic recession. In high-level concept, if due to a pandemic or deep recession approximately one third of utility customers were unable to pay their monthly electric bills over an extended time period, and this effectively resulted in the remaining two-thirds of utility customers paying for those costs through Z-Factor recovery, this added monthly expense could result in the remaining utility customers experiencing increased financial stress. In turn, this could result in more customers being unable to pay their monthly bills – creating a 'snowball' effect as to such

[56] *See* Haw. Rev. Stat. § 127A-1 for potential applicable definitions, e.g., "Disaster" means "any emergency, or imminent threat thereof, which results or may likely result in loss of life or property and requires, or may require, assistance from other counties or states or from the federal government" and "Emergency" means "any occurrence, or imminent threat thereof, which results or may likely result in substantial injury or harm to the population or substantial damage to or loss of property."

non-payments. This effect could be mitigated if Z-Factor payments are made over time, rather than at one time.[57]

D. Recovery Should Be Net of PIM Rewards and Penalties.

In addition and related to this approach, recovery of emergency costs pursuant to the Z-Factor recovery should be made on a basis that is net of any PIM rewards and penalties earned by the utility. For example, an emergency or natural disaster such as a hurricane may damage or destroy power lines, resulting in decreased electricity demand, decreased fossil fuel generation and decreased GHG emissions. Shelter in place orders during a pandemic may have a similar effect. If HECO is eligible for a PIM reward based on reduced GHG emissions under these circumstances, that reward must be netted out in determining Z-Factor recovery.

As another example concerning EoT, a pandemic could entail shelter-in-place orders which greatly reduce miles driven by electric vehicles ("EV"). This could result in a corresponding reduction in EoT PIM rewards earned by the utility, necessitating any penalty caused by this reduction to be netted out of Z-Factor recovery. This example further illustrates the need to evaluate, weigh and net out various PIM rewards and penalties in assessing Z-Factor recovery under the ARA.[58]

E. No Z-Factor Recovery of MPIR Expenses.

As an update to its earlier submissions, Ulupono notes that recovery under the Z-Factor would not include MPIR-eligible expenses, as explained by the Consumer Advocate in its

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[57] In this regard, Ulupono notes that in connection with the Covid-19 pandemic the Commission recently provided guidance and authorized utilities to establish regulatory assets and record costs for potential recovery in future proceedings, including "the appropriate period of recovery for the approved amount of regulatory assets." *See* Order No. 37125 (Non-Docketed) Addressing the Consumer Advocate's Request for Suspension of Termination or Disconnection of Regulated Utility Services due to Non-Payment and/or Assessment of Other Charges During the Covid-19 Pandemic" filed May 4, 2020 at 5.

[58] In a similar manner, during a pandemic such as the Covid-19 pandemic, reduced electricity demand may provide an opportunity for the utility to undertake certain types of repairs and maintenance at a cost that is lower than normal, and such savings should similarly be netted out from Z-Factor recovery amounts.

updated proposal. The Consumer Advocate's financial model excluded "[e]xogenous changes . . . based on the assumption that the utilities would accrue recoverable costs as regulatory assets for later recovery through Z-Factor provisions."[59] This approach is also consistent with D&O 36326, which directed the parties in Phase 2 to consider relief provided under the MPIR adjustment as distinct from potential relief under the Z-Factor.[60] Ulupono affirms its support for not including MPIR-eligible expenses for the same reasons.

F. Review of Hawaiian Electric's Z-Factor Examples.

In its First Proposal Update, Ulupono illustrated its position on the Z-Factor by reference to certain examples in the HECO Initial Proposal, which lists nine specific items.[61] These same items are listed in the HECO First Proposal Update.[62] As previously explained, Ulupono has no objection to use of the Z-Factor for the listed items concerning changes in accounting rules or tax laws and regulations, storms or catastrophic natural disasters, or force majeure events.[63]

Ulupono continues to not support application of the Z-Factor to "[r]egulatory, legislative, or judicial mandates or actions impacting the utility."[64] The formulation is overbroad insofar as there are a range of regulatory and other actions that may impact the utility – including implementation and adjustment of PBR mechanisms. The same concern applies to "[c]hanges in revenue requirements due to Commission decisions (e.g., depreciation rate changes)[.]"[65]

Similarly, to reinforce the cost control focus of PBR, the Z-Factor should also have limited or no availability for application to "[m]ajor unplanned maintenance costs or

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[59] CA First Proposal Update at 52.
[60] *Id.* at 33.
[61] *See* Hawaiian Electric Companies Initial Comprehensive Proposal filed Aug. 14, 2019 (Docket No. 2018-0088) ("HECO Initial Proposal") at 30-33.
[62] *Id.* at 47-48.
[63] *Id.* at 31-32 (example Z-Factor events 1, 2, 5, 6 and 8).
[64] *Id.* at 31 (example Z-Factor event no. 3).
[65] *Id.* at 32 (example Z-Factor event no. 7).

investments, such as those incurred due to unexpected major maintenance and major repairs to Company-owned power plants," insofar as such maintenance should reasonably be planned for and anticipated by the utility.[66] Similar to vegetation management and post-hurricane recovery, there could be a perverse incentive in the short run to defer maintenance and therefore reduce operations and management expenses, which may allow increased earnings relative to the largely fixed revenues and increases under the ARA. This type of perverse incentive and potential gaming should be avoided.

This concern applies equally to "[e]nvironmental remediation events," unless they involve pre-existing contamination (caused by a prior owner of the property, for example) that the utilities were unable to detect and assess in advance through reasonably diligent environmental site assessments.[67] Environmental remediation events may be based on the violation of existing environmental or pollution control laws. If such laws were in existence at the time the Commission adopts a revised PBR framework in this proceeding, then Z-Factor recovery should not be permitted because it was to a certain extent foreseeable and not sufficiently exogenous. If new environmental laws or requirements are imposed after commencement of PBR, however, the Commission may possibly take that into consideration, although the new requirements must be qualitatively different and incremental to existing environmental laws and requirements.

G. Ulupono Supports Proposed Materiality Thresholds.

Finally, a further update is that Ulupono agrees with and adopts as consistent with its position Hawaiian Electric's proposed Z-Factor "materiality thresholds."[68] Specifically, Ulupono supports materiality thresholds of $4 million for HECO and $1 million for MECO and

[66] *Id.* at 31 (example Z-Factor event no. 4).
[67] *Id.* at 32 (example Z-Factor event no. 9).
[68] *See* HECO First Proposal Update at 47-48.

HELCO. Under PBR, the materiality thresholds could be based on a percentage or basis points of revenue requirements. If the threshold was based on allowed revenues it would increase by operation of the ARA, which may be more appropriate relative to the static dollar amounts set in traditional rate cases that would no longer occur under PBR as proposed by Ulupono and other parties. If these materiality threshold amounts do not increase through the ARA, presumably they would increase according to the rate of inflation.

VI. EARNINGS SHARING MECHANISM

In this updated proposal, Ulupono confirms the attributes and function of its proposed ESM by recapping the discussion on this topic in its First Proposal Update.[69] As noted in the Initial Proposal, pursuant to D&O 36326 the ESM is intended to "share" amounts of utility earnings that "deviate substantially from a predetermined reasonable amount."[70] The ESM should include both upside and downside sharing (i.e., sharing and reverse sharing) which sharing amounts may or may not be symmetrical.[71] The ESM should also include a deadband or collar around the baseline level of earnings in which the ESM would provide no adjustment.[72] The basic functioning of Ulupono's proposed ESM is similar to that of the current ESM, under which the Commission determines a reasonable ROE or profit for shareholders, the authorized ROE, which is compared on December 31 each year to the utility's ratemaking ROE (which excludes certain items).[73] If the latter exceeds the former, a portion of the amount is credited to utility customers through the ESM.

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[69] *See id.* at 23-30.
[70] *Id.* at 32.
[71] Note that the term "sharing" refers to a percentage sharing of the basis points between two ESM breakpoints (rather than a sharing of the entire ROE percentage amount).
[72] Ulupono First Proposal Update at 32.
[73] *See* Ulupono Initiative LLC's Statement of Position filed March 8, 2019 (Docket No. 2018-0088) ("Ulupono SOP") at 15-17; Ulupono Initiative LLC's Reply Statement of Position filed April 5, 2019 (Docket No. 2018-0088) ("Ulupono RSOP") at 19-26.

A. Ulupono's ESM Achieves PBR Objectives Including Credit Rating Risk.

Ulupono's proposed ESM is intended to promote several key objectives of PBR. The ESM should support the use of PIMs that effectively incentivize utility achievement of energy policy objectives. At the same time, the ESM should protect the utility's credit rating from unintended and potentially extreme negative consequences of various PBR regulatory mechanisms.[74]

Ideally, the ESM should likewise protect utility customers from severe under- and over-compensation of the utility. Over-compensation of the utility indicates utility customers are paying too much, while under-compensation – to the extent it results in a loss of credit rating or other financial distress – can also lead to higher costs that are passed on to customers. These higher costs may be from increases in the utility's direct borrowing costs as well as from higher priced power purchase agreements ("PPA") which reflect the utility's lower (and more costly) credit rating.

Ulupono's refined and updated ESM is illustrated in Exhibit A-2[75] which demonstrates the impact on the four Moody's quantitative credit rating factors of a 5.5% ROE without ESM to the post-ESM (after sharing back to the utility) ROE of 6.3%. Without Ulupono's proposed ESM in place, a 5.5% ROE would likely result in a credit rating downgrade while the ROE with the ESM in place likely would not – the credit rating would be maintained based on the quantitative factors. This demonstrates the ESM's critically important ability to reduce the risk of a credit rating downgrade while allowing for bold PBR structures, such as those proposed by Ulupono in this proceeding.

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[74] *See* Ulupono RSOP at 26-29.
[75] Exhibit A-2, "Impact of Earnings Sharing Mechanism" ("Exhibit A-2"), attached.

Ulupono's ESM also addresses credit rating risk ("CRR"). Ulupono continues to propose that, for reverse sharing, the 90% level of sharing back to the utility be based on the ROE level at which there appears to be a CRR, i.e., risk based on the four quantitative factors that Moody's uses in assessing whether Hawaiian Electric's credit rating is likely to be downgraded. Based on the current authorized ROE and CRR, the 90% reverse sharing level should begin at an ROE of 5.5% (ROE < 5.5%). Further ESM breakpoints are as follows: 5.5% <= ROE < 6.5% results in 50% reverse sharing (to utilities); 6.5% <= ROE < 7.5% results in 25% reverse sharing; deadband of 2% above and below ROE creates 4% range of no sharing; 11.5% < ROE <= 12.5% results in 25% sharing (to utility customers); 12.5% < ROE <= 13.5% results in 50% sharing; and amounts over 13.5% result in 90% sharing.

B. ROE Volatility Is Also Addressed.

The structure of Ulupono's proposed ESM reduces the volatility of ROE, which should be supportive of the utility's credit rating and protective of utility returns. This structure would permit an ROE below the CRR only if the pre-ESM ROE were less than -2% (i.e., minus 2 percent, or a net loss, rather than 2 percent below Hawaiian Electric's authorized ROE). Establishing the 90% reverse sharing level at the point at which a downgrade seems likely would facilitate the adoption and implementation of bold PBR mechanisms, including the ARA and PIM structures, while remaining protective of the utility's credit rating. As explained above, under Ulupono's proposed ESM, there would be a deadband width of 4 percentage points (2 up and 2 down) where there is no sharing, but with graduated sharing at increasingly extreme ROE levels as described above. This ESM accordingly strikes a balance between the imperatives for strong performance incentives and responsible protection of the utility's credit rating and general financial integrity.

Importantly, Ulupono's analysis indicates that over the past eleven years, i.e., since 2008, there has not been a single achieved ROE for HECO, HELCO or MECO that would have resulted in a post-ESM ROE of less than 5.5% (assuming Ulupono's proposed ESM was applied to historic deviations between authorized and achieved ROEs). This adds confidence to the conclusion that Ulupono's proposed ESM would be sufficiently protective of the utility's credit rating.

C. ESM Operates with Cost of Capital Adjustment.

The ESM should operate in conjunction with a cost of capital ("COC") adjustment. For example, Hawaiian Electric previously proposed a COC adjustment mechanism.[76] Unlike the ROE percentage authorized by the Commission, the COC would start with the current authorized ROE but make adjustments based on independent market indices. Ulupono understands and continues to have no major objections at this time to Hawaiian Electric's proposed utilization of the California method, as described in their COC adjustment mechanism proposal, with modifications as described below.

The ESM should remain centered on the then-current authorized ROE pursuant to an acceptable COC adjustment. Under the type of adjustment supported by Ulupono, the 12-month average of the Moody's utility bond interest rate for the Moody's credit rating that the utility has at the time of measurement would be compared to the previous benchmark of this figure. If the difference exceeds a deadband of 1%, then the authorized ROE is adjusted by 50% of the entire difference between the new 12-month average and the previous benchmark (which may not be the prior year – it may precede the prior year because the benchmark average stays the same until the new 12 month average has a greater difference than the deadband).

[76] Hawaiian Electric's Initial Proposal at 33-36.

Note that upon commencement of the new PBR framework the initial benchmark should be calculated based on the immediately-preceding twelve-month period. Also, as the benchmark may have been calculated at a time when the utility had a different credit rating than in the new 12-month average period, this manner of adjustment should respond appropriately to changes in credit rating (either up or down).

The importance of this feature of the COC adjustment ties back to the proposed PBR Review score. Specifically, the asymmetric threshold to trigger a PBR Review is meant to give the utility an opportunity to earn a better credit rating. If a higher credit rating were to be achieved, the ratepayer should benefit from that in the form of an adjustment to the authorized ROE through this adjustment mechanism.

Finally, Ulupono does not support an automatic change in revenues based on an updated authorized ROE determined through the COC adjustment. It is axiomatic that the cost of debt will affect the utility's ROE, with higher debt costs lowering the ROE, and vice versa. Given that the ROE is adjusted through implementation of the ESM, however, a separate adjustment based on the cost of debt does not appear to be necessary or appropriate.

D. ROE Remains the Proper Measure for ESM.

As in previous submissions, for this update Ulupono continues to support the use of ROE as the proper unit of measure for the ESM. The reasons in support of this position are set forth in Ulupono's RSOP and Initial Proposal, and further explained in its First Proposal Update.[77] This update provides a further opportunity to summarize the bases for this position given its central importance to the proper functioning of the ESM, and the critically important

[77] *See* RSOP at 22-26 (explaining basis for position that EPS and EBITDA are not suitable as ESM units of measurement); Ulupono Initial Proposal at 11-12 (same); First Proposal Update at 28-30 (same).

role of the ESM in ensuring the utility's financial integrity as Hawaii embarks on an updated and potentially transformational PBR framework.

First, ROE is consistently used by the leading credit rating agencies to describe the financial health of utilities. These agencies include S&P, Moody's, and Fitch. For example, the August 2016 S&P Rating of HECO refers to HECO's ability to "continue to narrow the gap between earned and allowed returns on equity" as a vital factor in the utility's credit rating.[78] Similarly, the Fitch Ratings July 31, 2019 report on HECO refers to ROE as a key rating driver in its assessment of HECO,[79] and as the main method of comparison between peers.[80] ROE is also consistently discussed throughout Moody's October 2019 report on the utility,[81] and is used in reference to credit challenges,[82] investment,[83] and financial stability. Each of these prominent sources of credit reporting reflects the use of ROE as the preferred unit of measure.

Second, maintenance of an indirect link between utility investment and returns is plainly contemplated by section 269-16.1(a), Hawaii Revised Statutes. Under that provision, the Commission shall establish performance incentives and penalty mechanisms that "directly tie" an electric utility's revenues to its "achievement on performance metrics and break the direct link between allowed revenues and investment levels."[84] Use of the modifier "direct" with "link" suggests the usual and expected indirect link between investment and returns would remain intact.

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[78] Andrew Ng *et. al.*, RatingsDirect Hawaiian Electric Co. Inc., S&P Global Ratings, 1-12, 3 (2016) (emphasis added).
[79] *See* Fitch: Hawaiian Electric Co., Fitch Ratings Ltd, 1-14, 1 (July 31, 2019).
[80] *See id* at 3.
[81] Hawaiian Electric Co., Inc Update following positive outlook, Credit Opinion, Moody's Investors Service, at 2 (Oct. 2019).
[82] *Id* at 4.
[83] *Id.*
[84] *Id.* (emphasis added).

Third, maintaining an indirect link by using ROE as the ESM metric is also consistent with fundamental principles of financial theory, pursuant to which profits are properly evaluated by reference to levels of investment.[85] Investors, stock analysts, and debt rating agencies ultimately determine the utility's cost of debt and of equity based on several factors including earnings scaled by equity or assets. Unscaled earnings have little meaning in assessing a company's performance.[86]

Fourth, Ulupono remains unconvinced that use of an ESM will "work or pull regulation back to COSR."[87] This is especially true if the ESM is structured with a total deadband width of 4% of ROE, with tiered sharing outside of the deadband. The utility would have to be prepared to experience a significant decline in earnings to get to the point where 90% of excess costs or losses were shared back to the utility. Such a costly path to obtain COSR types of recovery is unlikely to be attractive to a profit-motivated company.

Finally, Ulupono is also unconvinced ESM alternative or replacement mechanisms are necessary or desirable. For example, Blue Planet proposes to use earnings per share ("EPS")[88] or Earnings Before Interest, Taxes, and Depreciation ("EBITDA")[89] as

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[85] *See* RSOP at 22-26.

[86] By way of illustration, a company with $1 million in equity or assets that earned a profit of $1 million in a year would be considered a major success while a company with $1 billion in equity earning only $1 million in profit would be considered a failure. Ulupono Initial Proposal at 12.

[87] Blue Planet SOP at 14-15.

[88] EPS is premised on the basic assumption that the business model or company capitalization (i.e., its mix of debt and equity) has not significantly changed in comparing prior to current EPS levels. As a simplistic illustration, a company may take on additional leverage (i.e., it increases the share of the company financed by debt, as for example through buying back equity). If all else remains equal, the EPS will increase – even though the total earnings may not change materially, while at the same time risk to the Company has increased. Even if EPS was used as the metric in an ESM, overinvestment would trend EPS lower, which could trigger downside or reverse sharing. In this respect, it is not superior to the use of ROE as the ESM metric.

[89] EBITDA is a shorthand way of comparing earnings over time when a business has not materially changed its business model, capitalization, risk profile, etc. EBITDA may not experience similar declines in value over time due to overinvestment, because its earnings are before depreciation and interest (which is relevant when overinvestment is funded by debt), but this does not alter investors' fundamental expectation of returns from investment. A fairly stable EBITDA will not deceive investors when net income – due to investments that make no return under an ARA – continues to mount, pressing the net income progressively lower.

alternative metrics to ROE.[90] Blue Planet further suggests that investors do not directly value the utility on ROE, but rather on EPS and how it translates to both dividends and expected earnings growth.[91] EPS and EBITDA are unscaled by a measurement of investment such as equity or assets, however, and thus fundamentally unequal and not superior to ROE or other forms of scaled earnings.[92]

E. Regulatory Accounting Concerns Should Not Hamper PBR Implementation.

Finally, the Phase 2 working group process has entailed consideration of whether implementation of certain PBR mechanisms may create an issue with regard to regulatory accounting conventions, including those generally referred to as Accounting Standards Codification section 980 ("ASC 980"). It is Ulupono's understanding that ASC 980 concerns, if any, may be at least partially addressed and mitigated by the adoption and utilization of a symmetrical ESM (that includes downside or reverse sharing) that is protective of the utility's credit rating. Such an ESM would signal the intent of regulators is to provide the utilities with a reasonable opportunity to cover costs and earn a return on investments (although the link would be less direct by design) through the PBR mechanisms, and as required by section 269-16.1, Hawaii Revised Statutes.

VII. MAJOR PROJECT INTERIM RECOVERY

For this Second Proposal Update, Ulupono reaffirms and refines its proposals regarding the MPIR adjustment mechanism. Pursuant to D&O 36326, the MPIR adjustment mechanism will continue to provide revenues, above revenues established by the ARA, for

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[90] Blue Planet SOP at 15.

[91] *Id.* at 15 n. 12.

[92] As further support for this conclusion, it should also be noted that even with an ESM based on ROE, Hawaiian Electric would not find over investing (i.e., building rate base or increasing the "E" in ROE) to be a profitable strategy, as they would lose money dollar for dollar over the ESM deadband and then only achieve partial recovery through reverse sharing. Indeed, such a strategy, if adopted, could be harmful to the utility's financial integrity.

"extraordinary projects" approved by the Commission.[93] Revisions to the MPIR Guidelines should be considered to "address capital bias that may be perpetuated through the current MPIR adjustment mechanism[.]"[94]

A. The MPIR Guidelines Should Allow Recovery for Grid Services and NWAs.

The MPIR adjustment should be available for Hawaiian Electric to recover non-capital expenses for grid services and NWAs. In this regard, Ulupono supports adoption by the Commission of language proposed by the Consumer Advocate concerning MPIR recovery of such expenses. The Consumer Advocate includes suggested revisions to the "Major Project Interim Recovery ('MPIR') Guidelines ("MPIR Guidelines") in its updated proposal.[95] These proposed revisions amending the definition of "Major Project" to include not only a "resource plant addition," but also to "deferred and/or amortized non-labor expenses[,]" provided the expenses total more than $2.5 million.[96]

Grid services and NWA projects offer benefits consistent with PBR policy objectives as they are likely to replace or obviate the need for traditional utility large physical plant capital expenditures (as opposed to smart grid technology, virtual power plants, etc.). This is broadly supportive of PBR cost control objectives – especially the need to "break the direct link" between utility revenues and capital expenditures.[97] Directionally, the promotion and addition of grid services and NWA projects may support the transition to a platform utility model insofar as the utility would contract for and not own the particular assets.

[93] Ulupono RSOP at 33.
[94] *Id.* at 34.
[95] *See* CA First Proposal Update at Exhibit 5, "Performance-Based Regulation – Docket No. 2018-0088 Consumer Advocate First Proposal Update – MPIR Revisions" ("Exhibit 5").
[96] CA First Proposal Update, Exhibit 5 at 2.
[97] Haw. Rev. Stat. § 269-16.1(a).

B. New Service Areas Should Qualify as Eligible Projects.

In this updated proposal, Ulupono similarly clarifies that it has no objection to use of the MPIR adjustment for utility capital expenditures necessitated by new service area expansions. For example, under this proposal extensions of service to a new housing or development that previously did not have electrical service would qualify for an MPIR. With all else remaining constant, using MPIR adjustment for this purpose is reasonable and such expenditures should not necessarily be excluded by application of the MPIR Guidelines eligibility criteria.

To support this proposal, Ulupono suggests updating the MPIR Guidelines to include more specific definitions addressing new and unserved areas. Specifically, a new service area could be defined as tax map key ("TMK") parcel that has not previously been served by Hawaiian Electric, i.e., there has never been a utility customer at the address on the TMK parcel. Simple replacements or upgrades to existing utility infrastructure, however, would not constitute a new service area.

To further illustrate this proposal, if an existing building or a development is demolished or replaced with a new building or development of a similar size or electric demand, of if there is merely a modest expansion of the service at an existing development, it would not qualify as a new service area under the Guidelines. If a development is significantly expanding or being replaced and will have a larger electricity demand, however, the MPIR Guidelines should provide that there should be no MPIR recovery for the replacement share but recovery could be allowed for the new expansion, provided the utility provides sufficient justification.[98]

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[98] It is noted that utility recovery of costs for line extensions and substations may be governed by tariff rule, e.g., HECO Rule No. 13, "Line Extensions and Subdivisions." Such rules may provide for advances and refunds for overhead extensions to subdivisions and developments and underground extensions. Cost recovery for new service

C. MPIR Projects Should Undergo IGP or Stakeholder Review.

Ulupono continues to propose that the MPIR process should be modified to include meaningful stakeholder review for large MPIR projects that were not reviewed and approved through the IGP process. The monetary threshold for large MPIR projects is proposed by Ulupono as the lesser of $50 million or more in total estimated project cost or $1 per month of average customer utility bill impacts.

The IGP process is intended to provide a significant opportunity for stakeholder input. By contrast, the MPIR process currently does not provide for direct stakeholder input. Thus, Ulupono supports consideration of modifying the MPIR Guidelines to include opportunities for stakeholder review and input as a protective measure, primarily for MPIR projects that were not considered in an IGP plan.

Such stakeholder review would be consistent with the MPIR Guidelines insofar as they contemplate allowing recovery for projects that have undergone a utility planning process. Under the current MPIR Guidelines, only "Eligible Projects" qualify for the MPIR mechanism. Section III.B includes illustrative examples of eligible projects, including projects approved by the Commission pursuant to Hawaiian Electric's "ongoing . . . planning dockets[.]"[99] The IGP planning process meets this definition.

Similarly, the types of projects described in the MPIR Guidelines are the types of projects that IGP process would be expected to encompass. In section III.B, the MPIR Guidelines provide the following illustrative examples of Eligible Projects: "(a) infrastructure that is necessary to connect renewable energy projects; (b) projects that make it possible to accept more renewable energy; (c) projects that encourage clean energy choices and/or customer

areas under the MPIR adjustment should properly take into consideration Rule 13 or other applicable rules to ensure recovery is appropriately limited and potential double recovery is avoided.

[99] *Id.* at 4.

control to shift or conserve their energy use; (d) approved or accepted plans, initiatives, and programs; (e) utility scale generation; and (f) grid modernization projects."[100] The IGP process presumably encompasses all of these examples.

The IGP process may aid in addressing a range of concerns about potential misuse of the MPIR mechanism in a new PBR setting established through this proceeding. Ulupono continues to share the concern that the MPIR mechanism may "incent the utilities to seek recovery for more projects, programs, and costs, which will increase the need for additional rigorous evaluation and consideration of each application and business case."[101] There is also the need to avoid the inefficiencies associated with "piecemeal ratemaking"[102] and to help prevent "[o]verreliance on interim cost adjustment mechanisms, such as MPIR, to account for major investments included in a five-year IGP action plan could result in a cumbersome regulatory process and dilute the cost reduction incentives integral to an MRP."[103] The IGP process should help to address these concerns.

Finally, and consistent with the foregoing, the MPIR Guidelines should also be modified as necessary to ensure approval for baseline plant additions is not sought or granted through the MPIR process. As explained in Ulupono's RSOP, baseline plant additions constitute significant expenditures in the regulatory framework which are not subject to pre-approval proceedings.[104]

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[100] RSOP at 9-12.
[101] Staff Proposal at 30.
[102] *See, e.g.,* Division of Consumer Advocacy's Metrics Brief filed Jan. 4, 2019 (Docket No. 2018-0088) at 70-71 (piecemeal cost recovery is "inconsistent with cost control and affordability concerns and creates additional work to reconcile and ensure that such mechanisms are not being abused.").
[103] *Id.*, Exhibit D at 3.
[104] HECO SOP, Exhibit D at 5.

VIII. ENERGY COST RECOVERY CLAUSE

For purposes of this updated proposal, Ulupono has no major changes to its prior submissions concerning revenue decoupling and existing cost trackers.

With regard to the Energy Cost Recovery Clause ("ECRC"), Ulupono reiterates that the RPS-A may better incentivize switching to renewables. Ulupono supports the intent of the ECRC, especially the sharing of fuel costs (to give the utility 'skin in the game'), and does not propose any changes or modifications to the existing ECRC at this time. The sharing percentage is relatively small, however, and Hawaiian Electric has no control over fossil fuel pricing, which itself is highly volatile and driven by global supply and demand. By contrast, it is suggested that Ulupono's RPS-A PIM takes advantage of the relatively high degree of control Hawaiian Electric may have over procuring and interconnecting renewables, thus providing a strong incentive and robust PBR mechanism.

IX. OFF-RAMPS

For this update, Ulupono offers further clarification of its basic position, which is that PBR Review effectively constitutes a type of "off-ramp," and thus off-ramps in general are not needed insofar as PBR Review is available to address such concerns. Pursuant to D&O 36326, off-ramp mechanisms are to "provide for review of approved PBR mechanisms, pursuant to specified circumstances or conditions."[105] Ulupono submits that the purpose of an off-ramp is to allow for an adjustment to PBR mechanisms that would achieve the same or greater levels of protection of the utility's financial integrity without a return to COSR.

Ulupono's proposed PBR Review may itself be considered to constitute a PBR off-ramp. PBR Review, as may be triggered by a PBR Review score, is plainly intended and

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[105] *Id.* at 33.

designed to provide for Commission review and oversight concerning the interrelated functioning of various future PBR mechanisms – the primary function of an off-ramp.

Other PBR mechanisms may reduce or eliminate the need for a non-PBR Review off-ramp. Most importantly, a robust ESM, tested and verified through modeling using the RIST, ideally should provide a high level of confidence concerning the avoidance of any significant adverse impact on the utility's credit rating from the implementation of PBR mechanisms.[106] Furthermore, adoption of a Z-Factor consistent with Ulupono's comments should also be protective of the utility's financial integrity as to events that are exogenous both to the utility and to PBR as a regulatory construct.

As a basic principle, a PBR framework featuring carefully-designed mechanisms should greatly reduce if not eliminate the need for off-ramps separate and apart from the functioning of the individual PBR mechanisms in combination with PBR Review at critical junctures. Ideally, any PBR mechanisms adopted in this proceeding should be implemented in a manner that is carefully considered to proactively address in advance and minimize outcomes significant enough to threaten the utility's financial integrity. To the extent this is planned for and accomplished off-ramps would not be necessary. Ulupono also shares the concern that off-ramps may dilute the cost control benefits of PBR.

In summary, when viewed holistically the PBR framework should generally obviate the need for off-ramps other than PBR Review. The Z-Factor removes the need for off-ramps due to exogenous events. The ESM removes the need for off-ramps due to mis-specification of the PBR structure during a five-year MRP period. In addition, PBR Review and the objective scoring process outlined in this proposal accommodate the need for structural

[106] As explained above, under the proposed ESM structure the utility would likely need to earn a pre-ESM ROE of -2% to fall below the estimated CRR of 5.5% (after the ESM).

revisions upon the conclusion of a five-year MRP. Accordingly, no off-ramp other than PBR Review is needed.

X. PERFORMANCE INCENTIVE MECHANISMS

As explained below, Ulupono updates its proposal concerning PIMs by adding a new PIM focused on GHG emission reductions, consistent with Commission guidance, and by providing further support for its RPS-A and EoT PIMs. Ulupono also provides in this Second Proposal Update its detailed benefit-cost analyses ("BCA") in support of its RPS-A, GHG and EoT PIMs.

Pursuant to D&O 36326, the Commission has prioritized the development of three to six new PIMs addressing the specific outcomes of Customer Engagement, DER[107] Asset Effectiveness, and Interconnection Experience. PIMs promoting achievement of the Customer Engagement and DER Asset Effectiveness outcomes will be "upside only," providing Hawaiian Electric with "financial rewards based on exemplary performance," while the Interconnection Experience outcome-related PIMs will have both penalties and rewards. All PIMs are to be developed in a manner that is consistent with the approved "PIM-specific design considerations."[108]

More recently, the Commission provided guidance encouraging parties to consider proposing GHG emission reduction PIMs and EoT PIMs, as well as mechanisms focused on cost control and reduction in ECRC and purchase power adjustment clause ("PPAC") costs ("cost control PIM").[109]

[107] Distributed Energy Resource ("DER").
[108] *See* Order No. 36326 at 42-49.
[109] PWG Meeting #6 Summary Notes at "Additional Guidance."

A. PIMs Should Focus on Outcomes Rather than Programs or Technologies.

Ulupono's proposal concerning PIMs to achieve the three priority outcomes identified in D&O 36326 should be understood in the context of its PBR guiding principles set forth earlier in this proceeding. First, and as previously explained, the goal of PBR should be the selection and implementation of the lowest (net present value) price energy solutions capable of achieving the 100% RPS requirement. Second, PBR should provide incentives that result in the selection of energy solutions that are agnostic as to utility or non-utility ownership.[110] Third, PIMs should encourage selection of the lowest cost energy solution for a specific articulated need, regardless of the technology, the utility program, or both.

Consistent with these principles, although Ulupono supports the investigation of PIMs tailored to the three identified outcomes, Ulupono also continues to strongly support and propose an outcome-based (as opposed to program- or technology-based) approach. Ulupono's proposed RPS-A PIM remains the primary example and focus because it is likely to significantly advance achievement of at least two of the priority outcomes, DER Asset Effectiveness and Interconnection Experience. And as explained below, it would do so in a simpler and more robust outcome-based manner as compared to a portfolio of smaller, programmatic PIMs. This is consistent with the Commission's recent guidance indicating that "[w]here proposed PIM metrics are based solely on program penetration or participation, <u>exploration of alternative outcome-based metrics is welcome</u>"[111] and that "PIMs should focus on <u>measurable progress</u> . . . rather than <u>tallies of program enrollment or participation</u>."[112]

[110] For clarity, Ulupono generally has no objection to competitive procurements allowing utility self-build options or affiliate offers, provided there is full compliance with applicable legal standards (e.g., for utility self-build options full compliance with the applicable Affiliate Transaction Rules).

[111] Commission Staff, Guidance for PBR Phase 2, Working Group Meetings, February, 2020 (Feb. 13, 2020) ("Feb. 2020 Staff Guidance") at 3 (emphasis added).

[112] PWG Meeting #6 Summary Notes at "Additional Guidance" (emphasis added).

Outcome-based PIMs are inherently superior to a suboptimal variety of program or activity based PIMs in part because evaluation and weighting PIMs on different programs, technologies, or solutions will result in a portfolio of generation and services that is weighted accordingly. Despite best efforts, this weighting is likely to be incorrect. It is difficult to prescribe or predict with sufficient certainty the mix of programs or technologies that is likely to be the least-cost path to achieving Hawaii's clean energy goals, including the 100% RPS mandate. Prices and technologies will change over the years in ways that are difficult or impossible to predict. A commitment to frequently and repetitively change and adjust the weighting of PIMs would be needed. An outcome-based PIM (such as the RPS-A) may help avoid the mistakes of incentivizing a suboptimal portfolio of solutions. Outcome-based PIMs also provide the utility and regulators with maximum flexibility to choose the least cost solution to achieve the identified PBR outcome.

B. PIM Reward Costs Are Limited by the ARA and Commission Review.

The costs of PIM rewards should be structurally limited by the PBR framework and operation of the non-PIM PBR mechanisms. The ARA is intended to foster cost control and set relatively fixed utility revenues. As a basic principle subject to Commission oversight, utility spending to achieve PIM rewards should remain less than the total amount of such rewards. Commission review of utility costs of PIM rewards for RPS-A or EoT incentive rewards, for example, should be limited by the PBR framework but also subject to Commission oversight to ensure PIM costs do not exceed PIM rewards. If revenues are largely fixed and only adjusted by the ARA, as a general principle it would not be in the utility's financial interest to spend more in achieving a PIM reward than the reward itself is worth.

A potential exception to this general principle would be recovery through MPIR projects. The utility could propose expensive MPIR projects to foster and enable the achievement of PIM rewards Although certain MPIR-eligible projects could be helpful and appropriate to accelerate RPS, EoT and other priorities that may be subject to PIM rewards, the Commission's prudence review of utility costs will remain critical to PBR implementation. In short, in the absence of recovery through the MPIR, revenues are largely fixed through the MRP such that the utility would be likely to control its spending to ensure costs do not exceed the value of the rewards. If MPIR projects are proposed to cover the cost of achieving PIM rewards, however, the usual prudence review – along with the stakeholder input Ulupono is proposing be a part of large MPIR projects that were not approved through IGP – will remain a critically important consideration.

C. Ulupono's PIMs Address Cost Control PIM Objectives.

The Commission has requested the parties consider development of a PIM that focuses on the potential reduction of costs to utility customers associated with the ECRC and the PPAC. For example, in the February 2020 Staff Guidance, parties were "encouraged to propose SSMs or PIMs that are indexed on and incent reductions" in fuel and purchased power costs.[113] The Staff Guidance encouraged such focus by the parties "in light of the magnitude of possible desirable reductions in ECRC and/or PPAC costs in proportion to the magnitude of utility earnings."[114]

Consistent with this guidance, Ulupono proposes that the goal of such a cost control PIM may be understood primarily in terms of the PPAC. It is well understood that as renewable generation is added to the utility's system, to achieve RPS compliance, the share or contribution of the PPAC to customers' bills is expected to increase and the share of ECRC is expected to decrease correspondingly. Thus, in the context of this discussion of a cost control

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[113] *Id.* at 3.
[114] *Id.*

PIM, the goal may be properly understood as increasing the PPAC charge by the lowest possible amount as Hawaii moves toward 100% renewable energy.

Ulupono submits that the collective effect of its proposed PIMs and SSMs will achieve this objective – increasing the PPAC charge by the lowest possible amount – in a manner that is superior to and obviates the need for a separate cost control PIM. PPAC costs can best be minimized through competition (specifically, competitive procurement of renewable generation and storage), the use of customer-sited renewable energy (especially when exported energy is credited at a rate less than the cost of utility scale resources), and SSMs (for grid services and NWAs) which simultaneously provide a market signal and an incentive to the utility to obtain renewables at lower prices.

Ulupono's proposed RPS-A and GHG Emissions Reduction PIMs will both provide a strong incentive to reduce ECRC amounts (through less fossil fuel based power generation) while the combination of competitive procurements and SSMs help ensure the renewables come in at the lowest possible prices. Therefore, Ulupono's proposed PIMs and SSMs together with competitive procurements fully address these objectives.

The volatility of imported oil pricing poses a fundamental challenge to a separate cost control PIM. Any PIM designed to reward the utility for reducing the sum of ECRC and PPAC will largely be driven by the volatility of oil prices. It is undisputed that Hawaiian Electric has no control over this volatility. Thus, there is a concern that under a separate cost control-related PIM the utility would experience a 'feast or famine' of incentives based on the vagaries of imported oil prices. Even if this type of PIM were to control for or remove the effect of imported oil price volatility, doing so would artificially assign to volatile imported oil prices an attribute they do not possess, which is the long-term stability and largely fixed prices of renewable PPAs.

Thus, Ulupono respectfully submits that the sum of RPS-A, competitive procurements of utility scale renewables, SSMs, and customer-sited renewable energy will achieve the desired objective of minimizing the sum of ECRC and PPAC without the unintended consequences of other potential measures, including a separate cost-control PIM.[115]

XI. RENEWABLE PORTFOLIO STANDARD-ACCELERATED PIM

For this Second Proposal Update, Ulupono provides additional analysis and refinements in support of its proposed RPS-A PIM. As with its GHG Emissions Reduction PIM and EoT PIM, the discussion proceeds as follows: description of the PIM; discussion of how the PIM achieves priority (and also non-priority) outcomes; financial impacts of PIM rewards and penalties; and the BCA supporting the PIM.

A. RPS-A Is an Outcome-Based PIM.

The RPS-A PIM has been described in Ulupono's prior submissions and the following recaps the key features. As previously explained, a major aspect of the RPS-A is that it features an upside reward as well as the established downside penalty and therefore provides an opportunity for Hawaiian Electric to earn revenues for accelerating RPS achievement.

As is well understood, the RPS law establishes penalties but not rewards. Under section 269-92(c), if the Commission determines Hawaiian Electric[116] has failed to meet the RPS requirements the utility shall be subject to penalties in the amount of $20 per megawatt hour

[115] The RPS-A also advances cost control through the avoidance of unnecessary transmission and distribution costs that can be achieved through virtual power plants, renewable energy and storage, microgrids and similar advanced technologies as considered in the IGP process. This aligns with priorities in other key dockets involving microgrids and DERs, for example. The major cost driver focus should not be limited to fuel oil costs but should also include how the utility operations add or control costs.

[116] Hawaiian Electric may aggregate HECO, HELCO and MECO RPSs for purposes of RPS compliance. Haw. Rev. Stat. § 269-93(a). It is assumed RPS-A PIM rewards would likewise be based on Hawaiian Electric's aggregate RPSs.

("MWh") ("RPS penalty").[117] Although the Commission may waive the RPS penalty based on "events or circumstances that are outside of an electric utility company's reasonable control," this high profile, well understood and critically important statutory mandate remains asymmetrical.[118]

The RPS-A PIM is consistent with the RPS law insofar as it encourages Hawaiian Electric to exceed the current RPS. Under section 269-94, Hawaii Revised Statutes, "Waivers, extensions and incentives," the Commission is authorized to "provide incentives to encourage electric utility companies to exceed their renewable portfolio standards or to meet their renewable portfolio standards ahead of time, or both."[119] It is also consistent with section 269-16, which calls for basing performance incentive and penalty mechanisms in part on the "rapid integration of renewable energy sources, including quality interconnection of customer-sited resources."[120]

As explained in the Initial Proposal and First Proposal Update, the RPS-A PIM would be implemented through one penalty mechanism and two reward mechanisms. The penalty mechanism is expected to be the same as exists under the current RPS law (and based on the statutory RPS). The first reward mechanism would utilize the years and percentage amounts established by the RPS law ("statutory year reward").[121] The second mechanism would utilize

[117] *See* Decision and Order No. 23912 filed Dec. 21, 2007 (Docket No. 2007-0008) (adopting RPS penalty framework); Order Relating to RPS Penalties filed Dec. 19, 2008 (Docket No. 2007-0008) (approving penalty of $20/MWh).
[118] Haw. Rev. Stat. § 269-92(d).
[119] *Id.* (emphasis added).
[120] Haw. Rev. Stat. § 269-16.1(b)(6) (emphasis added).
[121] Section 269-92, Hawaii Revised Statutes, "Renewable portfolio standards," subsections (a)(3) through (5), establish renewable portfolio standards of thirty percent by December 31, 2020, forty percent by December 31, 2030, seventy percent by December 31, 2040, and one hundred percent by December 31, 2045 (collectively, "RPS requirements"). For illustration purposes, under section 269-92(a)(4), the RPS requirement is forty percent (statutory RPS) of the utility's net electric sales by December 31, 2030. If the utility achieves more than forty percent (corrected RPS) by December 31, 2030, it has accelerated achievement of the RPS requirements for purposes of this PIM and should receive the statutory year reward. Failure to achieve RPS (statutory) would make Hawaiian Electric subject to the usual RPS penalties.

the interim period between the above-described RPS statutory years ("interim period reward"). The interim period is the period between the statutory years.[122]

An important aspect of the RPS-A PIM is that statutory year and interim period rewards are based on a corrected calculation of the RPS. Under the present RPS law, the RPS calculation may be considered to be incorrect insofar as it allows the utility to claim higher renewable penetration than would be measured by renewable generation divided by total generation, as opposed to by net sales. Under the corrected methodology, RPS compliance will be evaluated based on renewable generation over total generation or total consumption of electricity, rather than over utility electric sales. Thus, correcting the RPS calculation will itself help to accelerate the adoption of renewable energy.

Assuming the RPS-A PIM is adopted, including the statutory year and interim period rewards (based on the corrected RPS calculation), Ulupono proposes a reward amount of $10 per MWh or 1 cent per kilowatt hour ("kWh"). It should be noted that these results are based on forecasted load and renewable generation under the Ulupono #1 scenario.[123] Ulupono acknowledges that other scenarios, with different loads and therefore different GWh amounts for certain RPS percentages, may be used with the RIST.

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[122] For illustration purposes, if graphed a straight line could be drawn between any two consecutive statutory years (i.e., 2020 to 2030, 2030 to 2040, and 2040 to 2045). This straight line between the two statutory years would establish a baseline for the interim period reward. If Hawaiian Electric's corrected RPS percentage was above the baseline during the interim period, it would be eligible for the reward. No penalty is proposed for failure to qualify for the interim period reward.

[123] A copy of the "Assumptions and Input Data for Ulupono #1 Scenario" was attached as Exhibit 1 to the Ulupono First Proposal Update. No changes have been made for this updated proposal and a copy is also attached for convenience as Exhibit D-4. Ulupono anticipates updating its scenario for the Statement of Position filing due June 10, 2020.

B. RPS-A PIM Achieves Priority Outcomes.

The RPS-A PIM should greatly aid in achievement of the prioritized outcomes adopted pursuant to D&O 36326, especially the DER Asset Effectiveness and Interconnection Experience outcomes.[124]

As explained above, the RPS-A PIM is expected to be particularly effective in part because it aligns with Ulupono's PBR guiding principles. Specifically, the RPS-A PIM should foster selection and implementation of the lowest (net present value) price energy solutions capable of achieving the 100% RPS requirement because most renewable energy additions will be competitively procured which helps keep prices down. The RPS-A PIM should also provide incentives that result in the selection of energy solutions that are agnostic as to utility or non-utility ownership.

Perhaps most importantly, the RPS-A PIM, especially when combined with Ulupono's proposed SSMs, should also encourage selection of the lowest cost energy, regardless of the particular technology or program. In short, the RPS-A PIM should also be able to fully align the utility on increased DER adoption and fast interconnection times through one relatively simple and powerful measure.

As Ulupono has explained and presented in the Working Group process, the RPS-A PIM achieves multiple PBR regulatory outcomes, as follows.

- *DER Asset Effectiveness*: DERs may be advantaged as they can be added to the system more quickly than competitive procurements.

[124] The RPS-A PIM will also aid achievement of the Grid Investment Efficiency outcome insofar as investments will facilitate interconnection and use of DER and utility-scale renewable generation, toward compliance with the RPS requirements. *See* Ulupono Brief #3 at 21-22.

- *Customer Engagement*: With a reward available every year, the utility will have an incentive to offer attractive programs to bring more customer-sited renewables on the system.
- *Interconnection Experience*: The reward will only be available after the renewable resource is interconnected, providing a strong incentive to expedite the interconnection experience for both utility-scale and customer-sited DER projects.
- *Cost Control*: The utility has no control over oil prices, but will have some control regarding how quickly they can add competitively priced renewables onto the system.
- *Affordability*: Renewables are now cost-competitive with oil and are generally contracted at fixed-price PPAs, providing customers with more affordable, less volatile rates over longer periods of time.
- *Grid Investment Efficiency*: With a strong incentive to accelerate the RPS, the utility will have the incentive to invest as efficiently as possible to ensure the system can support increased amounts of renewables under a more accelerated timeframe.
- *GHG Reduction*: Most renewable generation has zero GHG emissions at the source of generation.

A summary of the foregoing is presented in Exhibit B-2, attached, "Relationship of Ulupono PIMs to Priority Outcomes." The benefits of the RPS-A may also be summarized in relation to factors identified in the Working Group process:[125]

- *Intended Outcome*: Give the utility and the Commission flexibility to pick the most cost-effective solutions to get to 100% RPS; accelerate the achievement of the State's RPS; outcome focused to avoid sub-optimal weighting of the programs that increase RPS via more narrow, programmatic PIMs; and serve as a counterbalance to the RPS penalty.
- *PIM Metric*: Compliance with the corrected RPS (% and year-based milestone).
- *Target or Baseline*: RPS goals for 2020, 2030, 2040 and 2045, as established by statute. If the Company's corrected RPS percentage is above the statutory goals it is eligible for a reward; and straight line increases between statutory years – if the corrected RPS percentage is above the baseline during the interim period, the Company is eligible for a reward.
- *Basis for Target/Historical Performance*: Existing RPS standard and the Companies' renewable energy achievements to date (as documented in annual RPS filings).
- *Financial Incentive Amount and/or Formula*: Reward: $10/MWh for going above and beyond the established, corrected RPS goal and penalty as established by statute ($20/MWh if the Company fails to meet the RPS target).

[125] *See* Commission Staff, Hawaii PUC PBR Proceeding – Phase 2 PWG Meeting #5 Notes (Feb. 13, 2020) ("PWG Meeting #5 Notes") at "PIMs and SSMs."

- *Analysis Supporting Financial Incentive*: As the reward is annual and the penalty only on the statutory years, having the reward amount equal to one half of the statutory penalty amount per MWh is reasonable and the Ulupono #1 scenario combined with the RIST forecasted PIM values well within the 2% ROE band proposed by several parties for total PIM reward amount. The reward amount is also supported by the BCA for the RPS-A PIM.

The RPS-A PIM is expected to strongly support achievement of the DER Asset Effectiveness priority outcome. Although both DERs and utility-scale renewables count toward RPS-A rewards, utility-scale projects often require relatively lengthy review and approval processes. This includes competitive procurement, interconnection, Commission approval of PPAs, land use entitlements and permitting and approval processes.

By contrast, interconnection of DERs could be relatively expedited insofar as less administrative steps and approvals are required. Thus, the RPS-A PIM may strengthen the utility's commitment and alignment to adding DERs to the grid, because they will likely be a faster way to increase renewables and earn the RPS-A reward. They will also leverage mostly customer capital and assets rather than utility capital expenditures, and this will further advance the DER Asset Effectiveness outcome.

With regard to the Interconnection Experience outcome, the utility similarly will be unable to increase renewable energy (and earn the RPS-A reward) unless and until projects are interconnected. With an RPS-A reward available each year, Hawaiian Electric should align with the goal of interconnecting projects as quickly as possible.

Such alignment appears relatively unlikely if metrics for the Interconnection Experience outcome are based on contested and uncertain time periods, such as the amount of time it takes to complete interconnection of a renewable energy facility to the utility grid. Accurately determining and verifying such time periods – and the cause of any delays in meeting applicable deadlines – is likely to be more difficult and burdensome relative to simply calculating MWh to determine penalties and rewards under the proposed RPS-A PIM. This may be especially true given that interconnections have varying levels of difficulty and complexity. Similar challenges arising in evaluating conditional approvals. Ulupono suggests the availability of RPS-A PIM rewards may spur the utility to meaningfully reduce DER interconnection delays in relatively short order.

Ulupono reiterates that it favors emphasis on the proposed RPS-A PIM relative to this or other similar Customer Engagement-related PIMs. The goal of the latter is to expand customer choice. Insofar as the RPS-A creates a strong incentive for the utility to interconnect a wide range of renewable energy systems, it should have the indirect effect of promoting customer choice, thus helping to achieve the Customer Engagement outcome as well.

C. Financial Impact of RPS-A PIM Is Reasonable and Appropriate.

Modeling of the RPS-A shows its potential to allow the utility to earn significant rewards for meaningfully accelerating the achievement of the RPS. The RPS-A PIM is further described in Exhibit B-1, "Renewable Portfolio Standard – Accelerated (RPS-A)." This exhibit shows the renewable energy generation required by statute to avoid penalties in 2020, 2030, 2040 and 2045 with straight line increases between the statutory years; the corrected renewable energy generation required when dividing renewable energy by total electricity consumed rather than by net sales[126]; utility-scale, distributed, and total renewable energy per the Switch scenario;

[126] It should be noted with regard to the "Corrected RPS Generation" column in Exhibit B-1 that when the RPS calculation is corrected to be relative to total electricity consumption, including customer-sited renewable energy, a higher level of renewable energy is needed to achieve the same percentage goals.

the excess over the corrected RPS; and the pre-tax RPS-A incentive payment at $10 per MWh increased by inflation.

The financial impact of the RPS-A PIM, as well as the GHG and EoT PIMs discussed below, are described in Exhibit B-14, "RPS-A, EoT Incentive, and Shared Savings Mechanism impact, under Ulupono Initiative Second Proposal Update ("Exhibit B-14"); Exhibit B-15, "RPS-A, EoT Incentive, GHG and Shared Savings Mechanism impact, under Ulupono Initiative Second Proposal Update" ("Exhibit B-15"); and Attachment C, "Financial Impacts of Ulupono's PBR Proposals" ("Attachment C"). Attachment C provides three detailed exhibits addressing the financial impacts of Ulupono's PBR proposals, including or related to its proposed PIMs. These exhibits provide analysis concerning revenue breakdowns,[127] financial metrics and impacts on residential customers,[128] and debt metrics and Hawaiian Electric's credit rating.[129]

Specifically, Exhibit C-1 shows the revenue breakdown for the status quo regulatory structure and a PBR framework based on Ulupono's Second Proposal Update, both utilizing the Ulupono #1 scenario in the RIST. Exhibit C-2 focuses on bill impacts, with slightly higher bills from obtaining improved performance. Exhibit C-3 assesses Moody's quantitative credit rating factors under Ulupono's updated proposal to demonstrate that it is not likely to harm Hawaiian Electric's credit rating. These exhibits are further supported by the information presented in Attachment D, "Regulatory Innovation Simulation Tool Exhibits," which include the RIST Excel model and discuss the RIST key components and recent updates.

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127 Exhibit C-1, "Revenue Breakdown: Ulupono Initiative Second Proposal Update v. Status Quo" ("Exhibit C-1").
128 Exhibit C-2, "HECO financial metrics and impacts on residential customers" ("Exhibit C-2").
129 Exhibit C-3, "Debt metrics demonstrate HECO will maintain credit rating" ("Exhibit C-3").

D. BCA Supports RPS-A PIM.

Consistent with the well-established and widely-recognized benefits of the RPS law, the proposed RPS-A PIM offers multiple benefits that are strongly supported by a BCA. For purposes of this Second Proposal Update, the BCA focus for the RPS-A PIM is on three interrelated benefits concerning avoided carbon emissions, reducing customer bill risk by increasing the fixed nature of utility customer bills due to reduced exposure to fossil-fuel pricing volatility, and resiliency benefits due to differences between on-site and imported energy. These benefits may be expressed in the following equation, which identifies the related PBR regulatory outcome from this proceeding:

Benefit of RPS-A PIM =

Carbon Reduction
(Greenhouse Gas Reduction Outcome)

+

Less Risk for Customers Through Fixed vs. Volatile Customer Bills
(Affordability Outcome)

+

Resiliency Benefits – Onsite v. Imported Energy
(Resiliency Outcome)

The factors in this equation are also supported by quantitative analysis concerning their respective financial values on a high, medium and low value basis, as illustrated in the following figure.

Fig. 2

"Renewable Portfolio Standard – Accelerated (RPS-A) Summary Benefit Cost Analysis"[130]

Renewable Portfolio Standard – Accelerated (RPS-A) Summary Benefit Cost Analysis (cents/kWh)					
Proposed Benefit	**Carbon Emission Reduction[1]**	**Customer Bill Risk Reduction (Fixed v. Volatile Bill)**	**Resilience**	**Total Benefit**	**Proposed RPS-A PIM Value as % of Total Benefit**
High Value	65 cents	5.2 cents	(?)	**>70.2 cents**	**<1.4%**
Mid Value	8.8 cents[2]	2.8 cents[3]	(?)	**>11.6 cents**	**<8.6%**
Low Value	7.4 cents	0.4 cents	(?)	**>7.8 cents**	**<12.8%**

[1] Value of Total Avoided CO2 per kWh above the Corrected RPS Line ($36 CO2 MT).
[2] The mid-value for Carbon Emission Reduction is the median value from the data set provided in the RPS-A BCA.
[3] The mid-value for Customer Bill Risk Reduction is the average value of high and low values.

Each of these factors and values may be further described as follows.

1. Value of avoided carbon.

BCA reinforces the value of the RPS-A PIM. For example, Exhibit B-4, "RPS-A BCA: Carbon Emission Valuation" ("Exhibit B-4"), attached, portrays the total avoided carbon emissions from using renewable energy, as in the Ulupono #1 scenario, based on oil-fired generation as the alternative. Relatedly, Exhibit B-3, "Carbon Pricing Initiatives – Price Comparison" ("Exhibit B-3"), attached, supports BCAs for Ulupono's proposed RPS-A, GHG and EoT PIMs. Exhibit B-3 supports a total cost for carbon emissions of $42 per metric ton ("MT"). While $42 per MT is the base cost of carbon in Exhibit B-3, Exhibit B-3 refers to $36 per MT because $6 per MT of cost is allocated to the GHG PIM, for a total of $42 per MT. In

[130] Values in the "Carbon Emission Reduction" column are based on Exhibit B-4, "RPS-A BCA: Carbon Emission Valuation" and values in the "Customer Bill Risk Reduction" column are based on Exhibit B-5, "RPS-A BCA – Customer Bill Risk Reduction." Total benefit amounts are listed as greater than because resilience values could not be calculated at this time. PIM value as a percent of total benefit is based on 1 cent per kWh divided by total benefit.

this way there can be confidence that the same value is not counted twice, despite the partial overlap of the RPS-A and GHG PIMs.

The values in Exhibit B-4 show the value if the total cost of avoided carbon were to be divided by only the kWh of renewable energy above the proposed RPS-A line just as the proposed 1 cent / kWh RPS-A incentive is only for outperformance above the RPS-A line. Even at $36 / MT, carbon cost alone shows a value (excluding the extreme values over $1, where the RPS-A is only narrowly exceeded) of between 7.4 and 65.1 cents / kWh – more than justifying a 1 cent / kWh (or $10 / MWh) RPS-A incentive.

2. Less risk for customers due to reduced volatility in customer bills.

The RPS-A PIM also reduces exposure to volatile oil prices (through increased exposure to largely fixed-cost renewables) and this is a further benefit to utility customers, who value having less risk or volatility in their monthly expenses. This is supported by Exhibit B-5, "Premium on electric bill in Hawaii to eliminate bill variation."[131]

As explained in Exhibit B-5, consistent in both financial theory and empirical research (or observed behavior) most people have a distinct aversion to risk or volatile costs. This tendency to prefer to pay a higher fixed price to avoid being exposed to a volatile price or cost is captured in a risk aversion coefficient. The higher the risk aversion, the higher a premium a customer would be willing to pay to avoid volatile prices/costs. The premium should also vary by customers' net worth and the correlation, or perceived correlation with stock market returns. There is some asymmetry in customers' reactions to volatile bills, a high electric bill when the stock market or the economy is down is perceived as significantly worse relative to the extent to which a low bill is perceived as beneficial when the economy is doing well.

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[131] *See also* Exhibit B-6, "Curriculum Vitae of George M. Constantinides."

Prof. George Constantinides (Leo Melamed Professor of Finance, The University of Chicago Booth School of Business), using a range of customer risk aversion coefficients, oil price to stock market correlations, and customers perceptions of risk, estimates a low and high value for what customers might be willing to pay as a premium to avoid volatile electric bills. This range is from $1 to $13 per month on an average $160 / month electric bill. Since historically, roughly one-half of customers' 500 kWh bills is based on fuel prices and one-half is roughly fixed (T&D and other charges), the $1 to $13 monthly premium value is divided by 250 kWh (one half the bill) to arrive at a per kWh value of fixed bills of 0.4 to 5.2 cent per kWh. *See* Exhibit B-5.

3. Resiliency benefits.

The RPS-A would enhance Hawaii's ability to overcome natural disasters and maintain a higher level of resiliency. In Hawaii, oil import terminals and oil-fired generation facilities are generally located at or near the shoreline. They are likely more susceptible to tsunami, hurricane, storm surge, and sea level rise as compared to wind, solar and other renewables that may be located further inland. Quantification of the resiliency value or benefit may prove challenging.[132] Ironically, valuation of a resiliency benefit may be more readily achievable during or after a natural disaster or other similar event that triggers the need for resiliency. This is because the event highlights the cost of siting infrastructure for importing and refining oil, and oil-fired generation, on or near the shoreline area which is exposed to natural disasters.

[132] Ulupono anticipates providing additional information on resiliency quantification in future submissions in this proceeding.

XII. GREENHOUSE GAS EMISSIONS REDUCTION PIM

Along with RPS-A, Ulupono supports consideration of a PIM focused on the reduction of GHG emissions ("GHG Emissions Reduction PIM") which is presented for the first time in this Second Proposal Update. As discussed below, Ulupono's GHG Emissions Reduction PIM shares certain attributes with the RPS-A PIM, and a detailed comparison of the two related PIMs is provided below. Based on its relative merits, and as explained below, Ulupono supports continued focus on the RPS-A PIM. This GHG Emissions Reduction PIM is proposed partly in response to guidance from Commission staff as well as the contributions of docket parties Blue Planet and the City and County of Honolulu, and other parties, in the working group process.[133]

A. Description of Ulupono's GHG Emissions Reduction PIM.

Under this PIM, Hawaiian Electric would earn a PIM reward for reducing GHG emissions. Exhibit B-7, "Greenhouse Gas Emissions Reduction PIM (GHG)," provides detailed information concerning the benchmark values and reward levels. As shown in Exhibit B-7, Ulupono's proposal includes benchmark values for CO_2 emissions, forecasts of GHG emissions based on modeling, and a description of three ways the PIM reward could be earned by Hawaiian Electric.

More specifically, Exhibit B-7 establishes benchmark values for CO_2 emissions starting with HECO's GHG Reduction Plan starting value for 2020, with straight-line reductions to zero in 2045, and GHG (CO_2) emissions as forecasted by the Ulupono #1 scenario based on the evolving generation mix. A GHG PIM reward could be earned for GHG emissions that fall below the benchmark emissions value; that fall below the previous year's GHG emissions; or

[133] *See, e.g.,* PWG Meeting #6 Summary Notes at "Additional Guidance" (Commission supports further development and specification of a PIM for the GHG emission reduction outcome).

through a combination of these two approaches. Ulupono supports the latter approach. Similarly, Exhibit B-3 provides detailed supporting information and analysis concerning establishment of the price of carbon for implementation of the PIM.

B. GHG Emissions Reduction PIM Achieves Priority Outcomes.

The GHG Emissions Reduction PIM would achieve most if not all of the same priority outcomes as the RPS-PIM. As explained below in the comparison of these two PIMs, they share many attributes. Accordingly, the GHG Emissions Reduction PIM is expected to provide similar achievement of priority outcomes.

C. Financial Impact of GHG Emissions Reduction PIM is Reasonable and Appropriate.

As explained above, the financial impacts of Ulupono's proposed PIMs and SSM are described in Exhibits B-14 and B-15, and Attachment C. These exhibits demonstrate and quantify the benefits of the proposed GHG Emissions Reduction PIM.

D. BCA for GHG PIM and Comparison of RPS-A and GHG PIMs.

Exhibit B-8, "RPS-A vs. Greenhouse Gas (GHG) Performance Incentive Mechanisms," details Ulupono's considerations and ultimate recommendation with regard to these two related PIMs, i.e., the RPS-A and the Ulupono GHG PIM. In short, although Ulupono remains generally supportive and open to considering a GHG PIM, the RPS-A appears to offer superior performance as an incentive to achieve desired outcomes and thus reduces the direct need for a GHG-focused PIM. Although there is some overlap in the outcomes covered by the RPS-A and GHG PIMs, there are important differences as well which further support this conclusion in favor of the RPS-A PIM.

For example, the RPS has a longer statutory precedent and the utility and regulators have more in-depth reporting history and experience with the RPS. At this time, there appears to be significant controversy over types of emissions that would qualify for GHG PIM rewards, including biogenic, waste-to-energy, and other similar types of emissions. By contrast, there is a broadly shared understanding of the statutory definition of renewable sources of energy under the RPS law.

The RPS-A PIM also appears to maintain a stronger nexus between utility action and PIM rewards. Under the GHG PIM, the utility would be unfairly rewarded for energy efficiency and conservation decisions made by customers, as well as for potential disaster-related reductions in load (if not netted out through the Z-Factor recovery process). The utility has little or no control over these circumstances. By contrast, under the RPS-A PIM the utility would not be rewarded for energy efficiency, conservation, or disaster-related drops in load.

In addition, EVs may be disincentivized under a GHG PIM as the increase in load will have a related increase in emissions until the utility reaches 100% RPS (even though the reduction in emissions from less gasoline usage in the transportation sector would far outweigh the increased emissions from the electrical sector). EVs would only potentially be disincentivized under the RPS-A PIM if the increase in load was serviced by burning more oil rather than from a decrease in curtailment of renewables. EVs can also be used in a grid supportive manner (through demand response ("DR"), time-of-use ("TOU") rates, vehicle to grid ("V2G"), and other similar programs) that could promote increased use of renewable generation.

Finally, GHG PIMs in general are further burdened by significant methodological controversies. This includes whether a point source or total lifecycle analysis is required to determine if GHG PIM rewards are warranted. For Hawaii, significant research would be required to develop total lifecycle emissions analyses insofar as generally available total lifecycle emissions data specific to Hawaii is not available.

Thus, lifecycle analysis would likely include a host of factors and considerations. This could include transportation emissions from the transport of fuel and equipment to Hawaii, as well as the sources or countries of origin of the individual components, such as the fuel oil, generation equipment, etc., and potentially even the manner in which they were produced. As an example, oil from offshore resources, shale fracking, tar sands and various other sources each have different total lifecycle emissions. Generally available total lifecycle emissions data is not specific to Hawaii. The only potential debate over the RPS is whether the focus should be on the statutory RPS definition or a corrected RPS which includes customer-sited resources in the denominator (rather than dividing by net sales).

For all of these reasons, Ulupono has an overall preference for the RPS-A PIM but is also willing to support a GHG or carbon emissions reduction PIM as a supplement to the RPS-A. *See* Exhibit B-8. To ensure Ulupono's proposed GHG PIM is straightforward to execute and consistent with existing applicable GHG statutory provisions and administrative rules,[134] the Ulupono GHG PIM calculations are modeled on non-biogenic emissions (i.e., emissions from biofuels, biomass and waste-to-energy processes are not included in the emissions forecasts), and based on emissions at the point source rather than total lifecycle emissions.

XIII. ELECTRIFICATION OF TRANSPORTATION PIM

Ulupono's suite of PIMs includes its EoT PIM not only because it expressly complements the RPS-A PIM, but also because it focuses on a critically important aspect of

[134] *See* 2007 Haw. Sess. Laws, Act 234; H.B. 226, 24th Leg. (Haw. 2007); Haw. Rev. Stat. § 342B, Part VI ("Greenhouse Gas Emissions").

PBR, which is clean transportation. It also responds to the request made in the Working Group process to consider development of an EoT PIM.[135]

A. The EoT PIM Achieves Priority Outcomes.

For its EoT PIM, Ulupono continues to propose that a small fraction, for example $.01 per kWh of utility revenues generated from the sale of electricity at electric vehicle ("EV") charging stations, should be made available to Hawaiian Electric as an EoT incentive payment. Like the RPS-A PIM, to illustrate the impact of the EoT incentive on Hawaiian Electric's revenues Ulupono has utilized the RIST to generate illustrative outputs. *See* Exhibit B-9: "Electrification of Transportation (EoT) PIM," attached.

B. EoT PIM Achieves Priority Outcomes.

Like the RPS-A, the EoT incentive presents a powerful opportunity to tackle climate and energy issues by means of a dedicated and straightforward PBR mechanism. As Ulupono has explained and presented in the Working Group process, the EoT PIM achieves multiple PBR regulatory outcomes, as follows.

- *Customer Engagement:* Electric vehicles are one environmentally responsible choice that customers increasingly want to make. Last year, EV sales in Hawaii were up 25% while internal combustion engine ("ICEV") vehicle sales remained flat.
- *Electrification of Transportation:* EoT is a priority because EVs are three times as efficient as ICEV, and put downward pressure on electric rates through decoupling (costs spread over more kWh), which benefits EV drivers

135 *See* Commission Staff, "Hawaii PUC PBR Proceeding – Phase 2 RWG Meeting #7" (April 22, 2020) ("RWG Meeting #7") at "Models for new revenue streams."

and non-EV drivers alike and can support the grid through daytime charging (excess renewables), DR, and eventually V2G technologies.

- *GHG Reduction*: EoT is a powerful way to reduce GHG; about 32% of Hawaii's fossil fuel consumption is for cars and light trucks versus only 28% for electricity generation. For example, a Nissan Leaf EV has half the total lifecycle GHG emissions as the average ICEV, and zero emissions at the tailpipe.[136]
- *Grid Investment Efficiency*: A higher integration of EVs on the system will provide the utility with increased opportunities to manage the system more efficiently through DR capabilities provided by EVs, such as peak shaving, time of use rates, V2G, and resiliency measures.

A summary of the foregoing is presented in Exhibit B-2. The benefits of the EoT PIM may also be summarized in relation to factors identified in the Working Group process:[137]

- *Intended Outcome*: Accelerate the reduction of imported fossil fuels (and the GHG) used in ground transportation; increase the use of EVs; increase deployment of metering at EV charging stations, enabling TOU rates for EVs, potentially DR, and in the future V2G; lower electricity prices through decoupling; and spreading costs over more kWh.
- *PIM Metric*: Sale of electricity ($/kWh) through EV charging stations.
- *Target or Baseline*: No target as every kWh delivered to an EV is eligible for the PIM reward.

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[136] Miotti , M., Supran *et al.* (2016). Personal Vehicles Evaluated against Climate Change Mitigation Targets . Environmental Science & Technology, 99.
[137] *See* PWG Meeting #5 Notes at "PIMs and SSMs."

- *Basis for Target/Historical Performance*: As EVs are relatively new and penetration is still only about 1%, rewarding all kWh to EVs seems reasonable.
- *Financial Incentive Amount and/or Formula:* Metered charging stations amount is \$0.03/kWh and non-metered charging stations amount is \$0.01/kWh. Presently, the vast majority of charging stations are not separately metered.
- *Analysis Supporting Financial Incentive*: For metered charging stations the analysis is based on actual kWh delivered and for non-metered charging stations, the analysis is based on kWh to be estimated based on the number of (1) registered EVs; (2) average miles per passenger vehicle (available from the State Energy Office); and (3) average efficiency of EVs (miles/kWh).

Other factual and policy-based reasons amplify the benefits of an EoT PIM. For example, giving the utility a financial incentive to deliver electricity to EVs would accelerate the reduction of an even greater source of imported oil dependence and GHG emissions than electric power generation itself, which is the transportation sector. For example, in 2018, 385 million gallons of fossil fuels were imported for electricity production while 511 million gallons were imported for ground transportation, according to the Hawaii State Energy Office.[138] Thus, ground transportation is a source of greater dependence on imported fossil fuels and greater source of GHG emissions.

Increased use of EVs provides benefits beyond fuel switching. In essence, every kWh consumed by an EV avoids the consumption of an equivalent amount of gas or diesel

[138] Hawaii State Energy Office, "Hawaii Energy Facts and Figures" (June 2019) at 3, *available at* https://energy.hawaii.gov/resources/dashboard-statistics.

automobile fuel in Hawaii. Given that EVs are approximately three times more efficient, however, and avoid approximately three times the energy amount in fossil fuels (gas and diesel) for each kWh delivered to an EV, there is an environmental multiplier effect when switching from gas and diesel to electricity. This multiplier effect in reducing emissions – driven by the higher efficiency of EVs – exists even if the EV kWh is not generated by renewables, and only increases as the grid takes on more renewable energy. *See* Exhibit B-10, "EoT BCA: Carbon Emission Valuation."[139]

Note also that growth in EoT stimulated by the EoT PIM is likely to benefit all utility customers whether or not they own an EV beginning on "day one" – even if the EoT incentive is a relatively high amount. In general, the Revenue Balancing Account ("RBA") results in lower prices when there are increases in decoupled electricity sales. Substantial amounts of electricity sales from growth in EoT are likely to contribute to lower prices – all else being equal – from the inception of the increased load growth from EoT.

As a further benefit, the EoT incentive will encourage the utility to install and utilize meters at charging stations. Ulupono proposes an incentive of $.03 per kWh for kWh delivered to EVs from metered charging stations, For estimated kWh delivered to EVs from non-metered charging stations, however, Ulupono proposes an incentive of $.01 per kWh. Increased installation and use of meters will generate data and information. This should further support the growth of EoT and allow development of the ultimate EoT metric and outcome, which is the replacement of fossil fuel used for transportation by MWhs of renewable electricity delivered to EVs. Furthermore, metered EV charging stations would be better able to participate

[139] For additional supporting information concerning the RPS-A, GHG, and EoT PIMs, see Exhibit B-12, "Stats & Sources for PIM Benefit Cost Analysis."

in DR, TOU rates, V2G and other grid-supportive activities and programs. These grid services could increase in total value dramatically as EV adoption accelerates.

C. Financial Impacts of EoT PIM.

The financial impacts of Ulupono's proposed PIMs and SSM are described in Exhibits B-14, B-15 and Attachment C.

D. BCA for EoT PIM.

Like the RPS-A and GHG PIMs, the proposed EoT PIM offers benefits that are supported by BCA. The three specific benefits are avoided carbon emissions, reduced customer bills due to decoupling and various grid benefits, and may be expressed in the following equation:

Benefit of Electrification of Transportation =

Carbon Reduction
(Greenhouse Gas Reduction Outcome)

\+

Customer Bill Reduction Through Decoupling
(Affordability Outcome)

\+

Grid Benefits (TOU, DR, V2G, etc.)
(Grid Investment Efficiency Outcome)

As noted above, the benefits of EoT are three-fold: Carbon reduction, the downward pressure on customers' bills (all else being equal) with the increase in load through decoupling, and grid supportive benefits of using EV charging stations for TOU rates, DR, vehicle to grid, and other grid supportive programs and services. The factors in this equation are also supported by quantitative analysis concerning their respective financial values on a high, medium and low value basis, as illustrated in the following figure.

Fig. 3

"Electrification of Transportation ("EoT") Summary Benefit Cost Analysis"[140]

Electrification of Transportation ("EoT") Summary Benefit Cost Analysis (cents/kWh)[1]

	Proposed Benefit 1: Avoided CO2 from Burning Gasoline[2]	Proposed Benefit 2: Additional CO2 from electric generation to charge Electric Vehicles[3]	Proposed Benefit 3: Bill Reduction Through Decoupling (Value provided to Ratepayers)[4]	Total Benefit (Proposed Benefit 1 – Proposed Benefit 2 + Proposed Benefit 3)	Proposed EoT PIM Value % of Total Benefit (1 cent/kWh)	Proposed EoT PIM Value % of Total Benefit (3 cents/kWh)
High Value	7.1 cents[5]	3 cents	10.3 cents[6]	**14.4 cents**	**6.9%**	**20.8%**
Mid Value	7.1 cents	1 cent[7]	7.7 cents[8]	**13.8 cents**	**7.2%**	**21.7%**
Low Value	7.1 cents	0	5.1 cents	**12.2 cents**	**8.2%**	**24.6%**

1Values do not include inflation (results in 2020 dollars).
2CO2 is valued at $42/MT.
3 CO2 is valued at $42/MT and calculation also assumes electricity delivered to EVs has the average fossil vs. renewable composition from power generated in the respective year.
4(Approved Base Revenues + ARA – Variable Generation O&M)/Net Load.
5 The values for 'Avoided CO2 from Burning Gasoline' are fixed based on average gasoline vehicle fuel efficiency in Hawaii (mpg) and average EV efficiency (kWh per mile) and was calculated using a value of $42 per CO2 MT.
6This is the forecasted value for 2030 (in 2020 dollars).
7The mid value of 'Cost of CO2 from Charging Electric Vehicles' is the median value of the data set presented in the EoT BCA at $42/MT.
8The mid value of 'Bill Reduction' is the average of the high value, which is the value in 2020, and the low value, which is estimated to be one half of the high value amount since EVs could possibly increase fixed costs to a degree.

It is further noted that carbon reduction has two basic components, which are increased emissions from servicing the increase in load, and significantly decreased emissions from the transportation sector from burning less gasoline. Decreased emissions from reduced gasoline use strictly dominates any increase in emissions from the electric generation to charge EVs.

The bill lowering effects of the increased EV load through decoupling can be estimated, and this bill lowering effect – from spreading fixed costs over more kWh – would benefit all utility customers regardless of whether they own an EV or not.[141] The value of grid supportive programs and services will not be separately valued in the EoT PIM benefit cost analysis as it is assumed that such services could be subject to Ulupono's proposed SSM.

140 Values in "Proposed Benefit" columns 1 and 2 are based on Exhibit B-10, "EoT BCA: Carbon Emission Valuation." Values in column 3 are based on Exhibit B-11, "EoT BCA – Bill Reduction through Decoupling." Total benefit subtracts benefit 2 from benefit 1 to net out carbon saved from gasoline, to which the bill reduction from decoupling amount is added to obtain the total benefit amount.
141 *See* Exhibit B-11, "EoT BCA – Customer Bill Reduction Through Decoupling," attached.

The basic rationale for decoupling is to remove utility's financial disincentive to embrace energy efficiency and renewable energy. Due to their attributes and abilities, EVs are functionally equivalent to energy efficiency measures and are likely to promote increased use of renewable energy. Therefore, sales of kWh to EVs should be incentivized through the EoT PIM and should not be disincentivized through decoupling.[142] Accordingly, Ulupono focuses on sales of kWh to EVs from metered charging stations and estimated amounts from non-metered charging stations.[143]

Ulupono's continued support for its proposed EoT incentive is based not only on the value to utility customers, but also the broader societal and environmental benefits associated with EoT. For example, and as noted above, according to the U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy, EVs are about three times as efficient as ICEVs, with ICEVs at 17-21% percent efficient and EVs at 59-62% efficient. EVs are more easily powered by renewable energy as renewable electricity is generally more readily available and more cost-competitive than most biofuels. In addition, EVs are zero emission vehicles at the tailpipe, and even when full lifecycle emissions (from manufacturing through disposal) are considered, EV emissions are about 50% lower than the sales weighted average ICEV and about 38% less than compact ICEVs.[144]

Further, EVs can enable the integration of more renewables with smart charging technology and rate structures. Accordingly, EoT represents a potential major source of load

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[142] SOP at 29-31.

[143] The estimated amount may be determined by calculating the total estimated kWh (using the formula of total number of EVs x average annual miles/EV x average kWh/mile) and then subtracting from that amount the total kWh from metered charging stations.

[144] *See* M. Miotti, *et al.*, "Personal Vehicles Evaluated Against Climate Change Mitigation Targets," *Environmental Science & Technology* 50, 20 (Sept. 2016) at 10799; *see also* Ulupono Initiative Comments on Hawaiian Electric Electrification of Transportation Strategic Roadmap filed July 12, 2018 (Docket No. 2018-0135).

growth and corresponding increase in utility revenues subject to the RBA that was likely not contemplated when the RBA was first put in place.

XIV. SHARED SAVINGS MECHANISM

Ulupono continues to strongly support use of SSMs, in addition to its proposed PIMs, for the reasons explained in its prior submissions. These factors are briefly recapped below.

A. Ulupono's SSMs Complement the RPS-A and Other PIMs.

As noted in D&O 36326, SSMs reward a utility for reducing expenditures from a baseline or projection by allowing it to retain a portion of savings as profit while returning the remaining amount to utility customers. Pursuant to D&O 36326, the Commission supports use of SSMs to aid achievement of the Grid Investment Efficiency outcome (by addressing utility capital bias) and the Cost Control outcome (by rewarding Hawaiian Electric for obtaining cost effective solutions to meet customer needs).[145] The SSMs also aid achievement of other priority outcomes, as explained in Exhibit B-2.

As an initial matter, it should be noted that the SSM and RPS-A PIMs are complementary and mutually reinforcing, and are not necessarily duplicative. The RPS-A PIM incentivizes the speed and volume of renewable energy needed to achieve RPS mandates and the SSMs should help to ensure renewable energy is procured at reasonable and cost-effective prices. Both the volume or amount of renewable energy and the cost are key to achieving the 100% RPS at the lowest net present value pricing. They are separate and distinct, and the utility may properly earn an award on both without double-counting.

To illustrate, a utility that consistently achieves but does not accelerate meeting RPS mandates, but does so with competitively-procured project pricing (with prices below

[145] *See id.* at 49-51.

Commission-established benchmarks), should properly qualify for shared savings sharing under the SSMs. Similarly, if the utility earns a reward under the RPS-A PIM for accelerating RPS attainment, but at prices that only meet, but are not lower than the Commission-established benchmark, the utility should also be eligible to earn the RPS-A PIM reward. Both the volume and speed of renewable additions, and the price at which they are procured, are separate and distinct factors in achieving the 100% RPS at the lowest possible cost.

To further highlight the potential unintended consequences of relying on an SSM alone to incentivize renewable energy, consider that a utility could, after the savings period expires, curtail or otherwise deprioritize renewable energy in order to justify an MPIR for new fossil generation, for example. Renewable energy use and its prioritization over fossil fuel use matters year after year, and is not a one-time decision as may be implied by the incentives of a short term SSM.

SSMs should continue to be used to encourage utility efforts to obtain low pricing for renewable energy PPAs, as was done in Hawaiian Electric's past and ongoing competitive bidding processes. In addition, in this Second Proposal Update, Ulupono further clarifies its support for the use of SSMs to encourage growth in competitive procurement of grid services and NWAs. SSMs can be used to promote increased reliance on DERs and NWAs.[146] The experience in New York of using SSMs to promote NWAs can continue to serve as a model for

[146] As explained in the Staff Proposal, for Phase 2 "Commission Staff recommends the development of shared savings mechanisms and the exploration of changes to expense treatment for DER or NWA. More specifically, a shared savings mechanism for the DR Portfolio and a shared savings mechanism for NWA would appear to be near-term priorities. In parallel to Phase 2 efforts, there may be opportunities to test shared savings mechanisms with existing projects and programs." *Id.* at 45 (emphasis added).

such efforts.[147] More broadly, it is noted that the use of SSMs is expressly authorized by statute.[148]

For effective SSMs of this nature, it will be necessary for the Commission to continue to determine the applicable benchmark pricing for the SSMs, i.e., the pricing which the utilities must procure below to qualify for the SSM sharing reward. For grid services and NWAs, the utility may need to provide the levelized cost of the conventional or wired alternative for the Commission to compare against a contract with an annual price, as opposed to a large capital cost.

Ulupono's support for such SSMs continues to be conditioned on firm bids, i.e., bids pursuant to which the bidder – including a self-build or utility affiliate offer – is responsible for any cost overruns. Under a bilateral PPA, the independent power producer is responsible for cost overruns, and to ensure a level playing field if the utility participates in a competitive procurement it must likewise bear the risk of such cost overruns.

Finally, Ulupono understands it may be advisable to establish the relative sharing percentages as between utility shareholders and customers on a mechanism-specific basis. Ulupono's view continues to be that SSMs should generally apportion not less than approximately thirty percent of the savings to the utility to ensure the utility is meaningfully incentivized. This amount is consistent with the examples from other jurisdictions, which fall in the range twenty to thirty percent.[149]

Ulupono's specific proposal in that regard, for this update, is as follows. The award should be based on savings from the purchase of kWhs (for PPA SSMs) over a two-year

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[147] *Id.* at 41, n. 72.
[148] *See* Haw. Rev. Stat. § 269-6(d)(1) (Commission shall consider whether establishment of shared cost savings incentive mechanisms is in the public interest).
[149] *See* Staff Proposal at 41.

period. The same time period should be employed for determining savings for grid services and NWAs, as compared to a baseline of the levelized cost of the wires (as opposed to non-wires) alternative. Ulupono is open to longer savings calculation periods for NWAs of up to five years, although Ulupono's RIST financial modeling uses a time period of two years to demonstrate the potential values and financial impacts, due to the utility's relative lack of experience with NWAs as compared to procuring renewable generation through PPAs. The promotion and addition of NWA projects may support the transition to a platform utility model insofar as the utility would contract for and not own the particular assets.

In further support of its proposed SSMs, Ulupono has conducted modeling using the RIST, the results of which are summarized in Exhibit B-13, "Shared Savings Mechanism: Renewable PPA and Grid Services/NWA."

XV. SCORECARDS AND REPORTED METRICS

In its First Proposal Update, Ulupono provided detailed comments on scorecards and reported metrics to focus on the identification of specific metrics for each of the outcomes. That summary document continues to reflect Ulupono's comments and proposals on these types of metrics and there are no further additions at this time. For convenience, the summary document is attached as Exhibit B-16, "Updated Reported Metrics."

XVI. CONCLUSION

For all of the foregoing reasons, Ulupono respectfully requests the Commission to consider the foregoing with regard to PBR in this proceeding, and grant any further relief the Commission deems just and proper.

DATED: Honolulu, Hawaii, May 13, 2020.

/s/ Douglas A. Codiga
DOUGLAS A. CODIGA
MARK F. ITO
Attorneys for Ulupono Initiative LLC

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Ulupono Initiative LLC's Second Proposal Update

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ATTACHMENT A
ANNUAL REVENUE ADJUSTMENT EXHIBITS

Exhibit A-1: "Proposed PBR Review"

This exhibit demonstrates how Ulupono's proposed annual PBR Review score, which is determined based on the post-Earnings Sharing Mechanism (ESM) Return on Equity (ROE), and the sum of five consecutive annual PBR Review scores, would indicate the need for PBR Review at the conclusion of a five-year MRP period.

For example, as shown in the exhibit a score of 4 in 2026 and 2 in 2031 would not trigger a PBR Review, with the exception that for 2026 review could be triggered if the utility had previously realized the proposed credit rating goals of BBB+, or equivalent, for all three credit rating agencies prior to the completion of the applicable five-year MRP.

This exhibit was prepared using Ulupono #1 scenario and RIST (5/6/2020).

Proposed PBR Review

	Post ESM ROE	Allowed ROE	Post-ESM ROE minus Allowed ROE	Annual PBR Review Score	PBR Review Score - 5 Year Sum	Triggered Review
2021	9.7%	9.5%	0.2	0		
2022	12.0%	9.5%	2.5	1		
2023	12.1%	9.5%	2.6	1		
2024	12.1%	9.5%	2.6	1		
2025	12.3%	9.5%	2.8	1		
2026	11.0%	9.5%	1.5	0	4	No [1]
2027	11.2%	9.5%	1.7	0		
2028	11.4%	9.5%	1.9	0		
2029	11.6%	9.5%	2.1	1		
2030	11.6%	9.5%	2.1	1		
2031	10.9%	9.5%	1.4	0	2	No

Automatic Review

Note: PBR Review Score is the sum of points assigned to the utility for the prior 5 years. Each year's score is based on where the post-ESM ROE falls. If it falls in the deadband it is zero, -1 for 3% below <= authorized ROE < 2% below, -2 points for 4% below <= authorized ROE <3% below, and -3 for more than 4% below authorized ROE. The point application is mirrored on the positive side. An PBR Review Score of 5 and above or -3 and below triggers a review, unless the utility has previously met the credit rating goals outlined in the Ulupono proposal

1) Due to the consistent earnings above authorized over the MRP, we assume that the credit rating goals may have been met and therefore simulate PBR review and rate resetting in 2026

Source: Ulupono Initiative Second Proposal Update, Ulupono Scenario #1 HECO O'ahu the RIST model (version 5/06)

Exhibit A-2: "Impact of Earnings Sharing Mechanism"

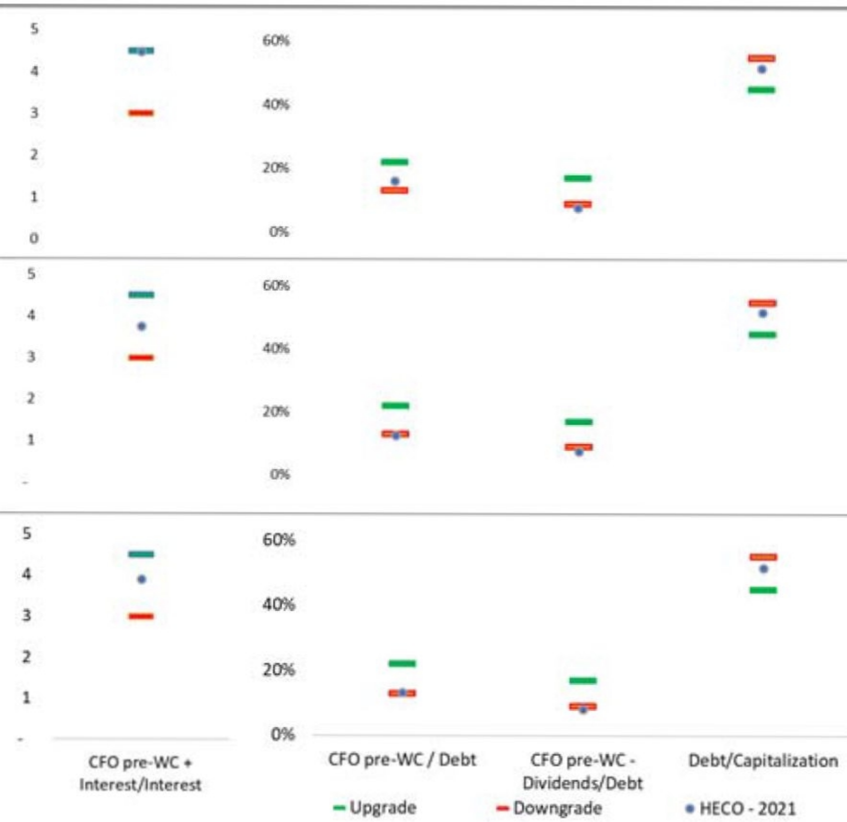
This exhibit demonstrates the impact on the four Moody's quantitative credit rating factors of a 5.5% ROE without ESM to the post-ESM (after sharing back to the utility) ROE of 6.3%. Without Ulupono's proposed ESM in place, a 5.5% ROE would likely result in a credit rating downgrade, while the ROE with the ESM in place likely would not, as the credit rating would be maintained based on the quantitative factors.

This demonstrates the ability of the ESM to reduce the risk of a credit rating downgrade, while allowing for bold PBR structures such as those proposed by Ulupono in this Second Proposal Update.

This exhibit was prepared using Ulupono #1 scenario and RIST (5/6/2020).

Impact of Earnings Sharing Mechanism

Scenario	ESM	ROE	Credit Metrics	Rating Impact
Ulupono #1 Scenario	Not applicable	9.5%		Maintain
Under-perform Scenario	Without ESM	5.5%		Downgrade
	With ESM	6.3%		Maintain



1) Single year under-performance, using 2021 as example, HECO O'ahu in the RIST model (version 5/06)
2) Underperform scenario shown with and without ESM with 2% deadband

ATTACHMENT B
PERFORMANCE INCENTIVE MECHANISM EXHIBITS

Exhibit B-1: "Renewable Portfolio Standard – Accelerated (RPS-A)"

This exhibit shows: (1) the renewable energy generation required by statute to avoid penalties in 2020, 2030, 2040 and 2045 with straight line increases between the statutory years; (2) the corrected renewable energy generation required when dividing renewable energy by total electricity consumed rather than by net sales; (3) utility-scale, distributed, and total renewable energy per the Ulupono #1 scenario; (4) the excess over the corrected RPS; and (5) the pre-tax RPS-A incentive payment at $10 per MWh increased by inflation.

This demonstrates the utility's potential to earn significant rewards for meaningful acceleration of RPS achievement. The Hawaii RPS law expressly authorizes actions to incentivize acceleration of RPS achievement.

This exhibit was prepared using Ulupono #1 scenario and RIST (5/6/2020).

Renewable Portfolio Standard - Accelerated (RPS-A) (pg. 1 of 2)

	Total Statutory RPS Generation [1]	Corrected RPS Generation [2]	Utility-Scale Renewables [3]	Distributed Renewables [3]	Total Renewable Energy [3]	Excess Renewable minus Corrected RPS	Pre-tax Incentive Payment at $10/MWh [4]
	GWh	GWh	GWh	GWh	GWh	GWh	$MM
2021	2,164	2,470	1,497	981	2,478	8	0.1
2022	2,201	2,526	3,156	1,020	4,177	1,651	17.2
2023	2,242	2,588	3,190	1,053	4,243	1,656	17.6
2024	2,288	2,659	3,224	1,093	4,317	1,658	17.9
2025	2,319	2,716	3,257	1,135	4,393	1,676	18.5
2026	2,357	2,786	3,273	1,179	4,452	1,666	18.8
2027	2,391	2,851	3,288	1,226	4,514	1,663	19.1
2028	2,434	2,920	3,305	1,265	4,570	1,650	19.3
2029	2,447	2,968	3,292	1,319	4,611	1,643	19.6
2030	2,476	3,029	3,286	1,360	4,646	1,618	19.7
2031	2,652	3,263	3,484	1,391	4,875	1,613	20.0
2032	2,865	3,534	3,689	1,423	5,112	1,578	20.0
2033	3,060	3,784	3,880	1,450	5,331	1,547	20.0
2034	3,263	4,057	4,056	1,492	5,549	1,492	19.7

1) Number to exceed in 2030, 2040, and 2045 to avoid penalties
2) Number to exceed in each year to earn reward
3) Per Ulupono Scenario #1, HECO O'ahu
4) The reward is $10/MWh in 2020 and inflates at 2% per year

Renewable Portfolio Standard - Accelerated (RPS-A) (pg. 2 of 2)

	Total Statutory RPS Generation [1]	Corrected RPS Generation [2]	Utility-Scale Renewables [3]	Distributed Renewables [3]	Total Renewable Energy [3]	Excess Renewable minus Corrected RPS	Pre-tax Incentive Payment at $10/MWh [4]
	GWh	GWh	GWh	GWh	GWh	GWh	$MM
2035	3,447	4,334	4,189	1,580	5,769	1,434	19.3
2036	3,649	4,631	4,274	1,656	5,931	1,300	17.8
2037	3,851	4,913	4,379	1,697	6,076	1,163	16.3
2038	4,059	5,219	4,434	1,766	6,200	981	14.0
2039	4,268	5,531	4,480	1,836	6,315	784	11.4
2040	4,508	5,868	4,544	1,892	6,437	569	8.5
2041	5,024	6,471	5,193	1,815	7,008	537	8.1
2042	5,598	7,094	5,705	1,723	7,428	334	5.2
2043	6,191	7,734	6,125	1,637	7,762	28	0.4
2044	6,817	8,420	6,491	1,577	8,069	(351)	-
2045	7,426	9,104	7,589	1,516	9,104	-	-

1) Number to exceed in 2020, 2030, 2040, and 2045 to avoid penalties
2) Number to exceed in each year to earn reward
3) Per Ulupono Scenario #1, HECO O'ahu
4) The reward is $10/MWh in 2020 and inflates at 2% per year

Exhibit B-2: “Relationship of Ulupono PIMs to Priority Outcomes”

This exhibit illustrates the relationship between Ulupono’s proposed performance incentive mechanisms (PIM) and the priority regulatory outcomes the Commission has identified in the PBR proceeding.

Renewable Portfolio Standard – Accelerated ("RPS-A")

Priority Outcomes	RPS-A
DER Asset Effectiveness	DERs may be advantaged as they can be added to the system more quickly than competitive procurements.
Customer Engagement	With a reward available every year, the utility will have an incentive to offer attractive programs to bring more customer sited renewables on the system.
Interconnection Experience	The reward will only be available after the renewable resource is interconnected, providing a strong incentive to expedite the interconnection experience for both utility scale and customer sited DER projects.
Cost Control	The utility has no control over oil prices, but will have some control regarding how quickly they can add competitively priced renewables onto the system.
Affordability	Renewables are now cost competitive with oil and are generally contracted at fixed price PPAs, providing customers with more affordable, less volatile rates over longer periods of time.
Grid Investment Efficiency	With a strong incentive to accelerate the RPS, the utility will have the incentive to invest as efficiently as possible to ensure the system can support increased amounts of renewables under a more accelerated timeframe.
GHG Reduction	Most renewable generation has zero GHG emissions at the source of generation.

Electrification of Transportation ("EoT")

Priority Outcomes	EoT
Customer Engagement	Electric vehicles are one environmentally responsible choice that customers increasingly want to make. Last year EV sales in Hawaii were up 25% while internal combustion engine (ICE) vehicle sales remained flat.
Electrification of Transportation	EoT is a priority because EV's are three times as efficient as ICE vehicles, put downward pressure on electric rates through decoupling (costs spread over more kWh)—which benefits EV drivers and non-EV drivers alike and can support the grid through daytime charging (excess renewables), demand response, and eventually, vehicle to grid technologies.
GHG Reduction	EoT is a powerful way to reduce GHG; about 32% of Hawaii's fossil fuel consumption is for cars and light trucks vs. only 28% for electricity generation. For example, Nissan Leaf EV has half the total lifecycle GHG emissions as the average ICE vehicle. *(Miotti , M., Supran et al. (2016). Personal Vehicles Evaluated against Climate Change Mitigation Targets . Environmental Science & Technology, 99.)*

Shared Savings Mechanism ("SSM")

Priority Outcomes	SSM
Grid Investment Efficiency	With an incentive for bringing in low cost resources, grid investment will be more financially prudent / efficient.
Cost Control	An incentive to bring in low cost resources will help control costs (especially when NWAs are lower cost as compared to conventional, wired alternatives) which would otherwise be the status quo.
Affordability	Lower cost procurements will help keep customer bills down.

Exhibit B-3: "Carbon Pricing Initiatives – Price Comparison"

This exhibit supports the BCA analyses that are linked to the cost of carbon, for Ulupono's RPS-A, GHG and EoT PIMs.

Many U.S. jurisdictions as well as countries around the world recognize that carbon emissions have a real cost or negative impact on society. This exhibit provides a sample of relevant values globally. In the Hawaii 2020 legislative session, S.B. 1050 (alive at the time the legislature went into recess as a result of COVID-19) proposed a carbon tax of $40 per MT in 2020, increasing to $80 by 2030.

Beginning in 2013, several public utility regulatory commissions in other states have established a low and high assigned value for carbon emissions. The values are primarily used to evaluate/quantify the potential impacts of certain investments identified in the utility's integrated resources plans, or to determine the value of distributed renewable generation on the system. The majority of commissions and state legislatures have consistently relied on the federal government's Interagency Working Group on the Social Cost of Greenhouse Gases, which operated from 2009 to 2017. The values provided remain the best source for the Social Cost of Carbon (SCC) estimates, with the Environmental Protection Agency and other agencies utilizing the SCC estimates in regulatory decision making.

For this evaluation, Ulupono used Year 2025 numbers (end of the first MRP under PBR) with varying discount rates, as well as a high impact scenario number for consideration. Values used by other Public Utilities Commissions as well as the theoretically correct Social Cost of Carbon numbers seem to be the most relevant for the BCA. Additionally, other stakeholders participating in the PBR proceeding have shared that the values proposed are aligned with their independent research. Carbon tax values from other countries as well as cap and trade initiative values are also portrayed for comparison.

While the cap and trade values may appear to be "market based," the decision of where to apply the cap is often at least partly a political decision designed to "act" on carbon emissions without overly impacting the industries to which the cap and trade applies. With a focus on Hawaii's carbon tax bill, the values used by other commissions, and SCC numbers, Ulupono estimates that $42 per MT CO2 is a highly defensible number, ranging on the low end of carbon emissions cost.

Carbon Pricing Initiatives – Price Comparison

Hawaii Proposed 2020 Legislation – S.B. 3150 (H.B. 2654)

\$40/MT CO2e in 2020, increasing incrementally, resulting in **\$80/MT CO2e** in 2030.[1]

Commission Established Values for the Social Cost of Carbon

	California[2]		Colorado[3]		Maine[4]		Nevada[5]	New York[6]	Washington[7]
State	Low	High	Low	High	Low	High	Low	Value	Value
Value Assigned	\$42 (IWG 2020 SCC)	\$123 (IWG 2020 SCC)	\$43 (IWG 2022 SCC)	\$69 (IWG 2050 SCC)	\$43 (IWG 2022 SCC)	\$69 (IWG 2050 SCC)	\$42 (IWG 2020 SCC)	\$32.47 (short ton of CO2e)	\$78

2025 Social Cost of Carbon (Based on 2017\$)[8]

2025 SSC - 5% Discount Rate	2025 SCC - 3% Discount Rate	2025 SCC -2.5% Discount Rate	2025 SCC - High Impact at 3% Discount Rate
\$17	\$55	\$82	\$166

Carbon Tax

British Columbia		Spain		Switzerland		Iceland	Norway	France	Finland
Low	High	Low	High	Low	High	\$36	\$64	\$69	\$77
\$27	\$39	\$12	\$37	\$101	\$221				

Cap and Trade Initiatives

Regional Greenhouse Gas Initiative ("RGGI")[9]

2019 Average Clearing Price	Low Value	High Value
\$5.42	\$5.20	\$5.62

California Carbon Emission Trading Program ("CA ETP")[10]

2019 Average Settlement Price	Low Value	High Value
\$16.83	\$15.73	\$17.45

European Union Emission Trading Scheme ("EU ETS")[11]

2018 Average Price	Low Value	High Value
\$15.60	\$0	\$21.59

Exhibit B-4: “RPS-A BCA - Carbon Emission Valuation”

This exhibit illustrates the total avoided carbon emissions from using renewable energy (as in the Ulupono #1 scenario) based on oil generation as the alternative. The total cost values are shown at both $36 and $42 per CO2 equivalent metric ton (CO2 MT). While $42 per MT is the base cost of carbon used in the benefit BCA, $36 is shown as well to recognize the allocation of $6 per MT of cost for the GHG Emission Reduction PIM, totaling $42 per MT.

This approach is intended to address the “double counting” concern, although there is only a partial overlap between the RPS-A and GHG PIMs. The per kWh values show the value if the cost of avoided carbon were to be divided by only the kWh of renewable energy above the proposed RPS-A line, just as the proposed 1 cent per kWh RPS-A incentive is only for outperformance above the RPS-A line.

Even at $36 per MT, carbon cost alone shows a value (excluding the extreme values over $1) of between 7.4 and 65.1 cents per kWh – more than justifying a 1 cent per kWh (or $10 per MWh) RPS-A incentive.

RPS-A BCA: Carbon Emission Valuation

Year	Total Renewable Energy (RE) (GWh)	Total Avoided CO2 MT (based on oil generation)	Total Cost of Avoided CO2 ($M) ($36 per CO2 MT)	Cost of Avoided CO2 from Total RE per kWh above Corrected RPS ($36 per CO2 MT)	Total Cost of Avoided CO2 ($M) ($42 per CO2 MT)	Cost of Avoided CO2 from Total RE per kWh above Corrected RPS ($42 per CO2 MT)
2020	2,401	1,952,051	$ 70.3		$ 82.0	
2021	2,478	2,014,653	$ 72.5	**$ 9.066**	$ 84.6	**$ 10.577**
2022	4,177	3,395,967	$ 122.3	**$ 0.074**	$ 142.6	**$ 0.086**
2023	4,243	3,449,626	$ 124.2	**$ 0.075**	$ 144.9	**$ 0.087**
2024	4,317	3,509,789	$ 126.4	**$ 0.076**	$ 147.4	**$ 0.089**
2025	4,393	3,571,578	$ 128.6	**$ 0.077**	$ 150.0	**$ 0.090**
2026	4,452	3,619,546	$ 130.3	**$ 0.078**	$ 152.0	**$ 0.091**
2027	4,514	3,669,953	$ 132.1	**$ 0.079**	$ 154.1	**$ 0.093**
2028	4,570	3,715,482	$ 133.8	**$ 0.081**	$ 156.1	**$ 0.095**
2029	4,611	3,748,815	$ 135.0	**$ 0.082**	$ 157.5	**$ 0.096**
2030	4,646	3,777,271	$ 136.0	**$ 0.084**	$ 158.6	**$ 0.098**
2031	4,875	3,963,452	$ 142.7	**$ 0.088**	$ 166.5	**$ 0.103**
2032	5,112	4,156,136	$ 149.6	**$ 0.095**	$ 174.6	**$ 0.111**
2033	5,331	4,334,187	$ 156.0	**$ 0.101**	$ 182.0	**$ 0.118**
2034	5,549	4,511,424	$ 162.4	**$ 0.109**	$ 189.5	**$ 0.127**
2035	5,769	4,690,288	$ 168.9	**$ 0.118**	$ 197.0	**$ 0.137**
2036	5,931	4,821,996	$ 173.6	**$ 0.134**	$ 202.5	**$ 0.156**
2037	6,076	4,939,884	$ 177.8	**$ 0.153**	$ 207.5	**$ 0.178**
2038	6,200	5,040,697	$ 181.5	**$ 0.185**	$ 211.7	**$ 0.216**
2039	6,315	5,134,194	$ 184.8	**$ 0.236**	$ 215.6	**$ 0.275**
2040	6,437	5,233,382	$ 188.4	**$ 0.331**	$ 219.8	**$ 0.386**
2041	7,008	5,697,614	$ 205.1	**$ 0.382**	$ 239.3	**$ 0.446**
2042	7,428	6,039,081	$ 217.4	**$ 0.651**	$ 253.6	**$ 0.759**
2043	7,762	6,310,628	$ 227.2	**$ 8.114**	$ 265.0	**$ 9.466**
2044	8,069	6,560,224	$ 236.2	**$ (0.673)**	$ 275.5	**$ (0.785)**
2045	9,104	7,401,695	$ 266.5		$ 310.9	

Exhibit B-5: “RPS-A BCA – Customer Bill Risk Reduction - G. Constantinides, Premium on electric bill in Hawaii to eliminate bill variation study”

Consistent with both financial theory and empirical research (or observed behavior), most people have a distinct aversion to risk or volatile costs. This tendency to prefer to pay a higher fixed price, to avoid being exposed to a volatile price or cost, is captured in a risk aversion coefficient.

The higher the risk aversion, the higher a premium a customer would be willing to pay to avoid volatile prices/costs. The premium should also vary by customers' net worth and the correlation, or perceived correlation with stock market returns.

There is some asymmetry in customers' reactions to volatile bills – a high electric bill--when the stock market or the economy is down – feels significantly worse than a low bill--when the market/economy is up – feels good.

Dr. George Constantinides (Leo Melamed Professor of Finance, The University of Chicago Booth School of Finance), using a range of customer risk aversion coefficients, oil price to stock market correlations, and customers' perceptions of risk estimates a low and high value for what customers might be willing to pay as a premium to avoid volatile electric bills.

This range is from $1 to $13 per month on an average $160 per month electric bill. Since historically roughly one-half of customers' 500 kWh bill is based on fuel prices and one-half is roughly fixed (T&D and other charges), we divide this $1 to $13 monthly premium value by 250 kWh (one half of the bill) to arrive at a per kWh value of fixed bills of 0.4 to 5.2 cents per kWh.

To: Mr. Murray Clay

From: George Constantinides

Date: April 26, 2020

Re: Premium on electric bill in Hawaii to eliminate bill variation

I have been asked to determine the monthly premium (PREM) that a typical customer with typical average electric bill of $160 is willing to pay in order to eliminate fluctuations in the monthly bill. The premium is defined as the premium that makes a customer indifferent between a fixed bill of $160 + PREM and a variable bill with mean $160. I estimated the range of the premium in two different ways, one based on the customer's risk aversion and the other based on a customer's comparison of the bill's fluctuations with stock market fluctuations. My overall conclusion is that a fair estimate of the monthly premium lies between $1 and $13. This conclusion takes into account realistic limitations of the average customer to perform intricate financial calculations.

Calculation of the monthly premium (PREM) based on risk aversion

As inputs, I need to estimate the residential power bill volatility, the relative risk aversion (RRA) of the average customer, and the net wealth of the average customer.

The monthly electric bill in Hawaii is $160, on average. Half of the bill is fixed at about $80. The other half is variable with annualized monthly volatility 25%. Therefore the variance (squared volatility) of the monthly $160 bill is $\sigma^2 = 80 \times 0.25^2 / 12 = 0.4167.$ About half the bill is passed through fuel prices. So, 50% of the bill, used to be based on oil with 25% annualized volatility (for prices in Hawaii which are a bit different than oil indexes). However, for more than ten years now the utility has been increasing renewable energy which has fixed price so the volatile part of the bill becomes lower and lower. This gives the same estimate of the variance of the monthly $160 bill as $\sigma^2 = 80 \times 0.25^2 / 12 = 0.4167.$

I calculate the relative risk aversion of the average household as follows. I take the stock market annual mean return as $R_M = 9\%$ based on the following historical evidence: 1966-2015 9.69%, 1916-1965 10.36%, and 1871-2015 9.05%. I take the stock market annual volatility of return as $\sigma_M = 18\%$, the historic mean value of the VIX index. I take the annual mean risk free rate as $R_F = 1\%$ based on the 3-month Treasury bill rate. Then the implied relative risk aversion coefficient (RRA) is $RRA = \left(R_M - R_F\right)/\left(\sigma_M\right)^2 = \left(0.09 - 0.01\right)/\left(0.18\right)^2 = 2.5.$ Using household data, Constantinides and Ghosh (*JF* 2018) estimate the RRA coefficient between 1.2 and 13.3. I present estimates of the certainty premium with RRA =2, 5, and 10.

The net wealth of the average household (W) consists of a residence, bank deposits, social insurance savings, and investments in equities, bonds, and other financial assets, net of mortgage loans and other debts. The estimated net wealth is low, varying from $500 to $10,000. I present estimates of the certainty premium with W = $500, $1,000, and $10,000.

Based on standard economic theory and inputs $RRA = 2, \sigma^2 = 0.4167, \text{ and } W = 500$ the monthly premium is given as

$$PREM = \frac{RRA \times \sigma^2}{2 \times W} = \frac{2 \times 0.4167}{2 \times 500} = \$0.0008.$$

If the inputs are $RRA = 5, \sigma^2 = 0.4167, \text{ and } W = 500$ the monthly premium is given as

$$PREM = \frac{RRA \times \sigma^2}{2 \times W} = \frac{5 \times 0.4167}{2 \times 500} = \$0.0020.$$

If the inputs are $RRA = 10, \sigma^2 = 0.4167, \text{ and } W = 500$ the monthly premium is given as

$$PREM = \frac{RRA \times \sigma^2}{2 \times W} = \frac{10 \times 0.4167}{2 \times 500} = \$0.0042.$$

In all cases the premium is extremely small, less than one cent. If the net wealth is higher than $500, say 1,000 or $10,000, the premium is even smaller.

A major caveat is in order. The above calculations would challenge even MBA students with finance background. It is questionable whether customers explicitly think in terms of the risk aversion coefficient and distinguish between the crucially different concepts of relative risk aversion and absolute risk aversion. It is also questionable whether customers can accurately estimate their net worth. Because of these reservations, a different type of calculations is presented next that provides a more credible value of the electric bill premium.

Calculation of the monthly premium (PREM) based on stock market comparisons

The stock market in the US has experienced large price variation: in October 22, 1987 the DJIA fell by 22.6%; by mid-2008 the DJIA fell by 20%; and in March 2020 the market fell by 33% and then partly recovered. The VIX which is normally around 18% shot up to 80% during these crises. Thus the stock market has experienced large variations and historically commands an average annual premium of 8% or 0.67% monthly.

The electric bill in Hawaii has experienced large variation just as the stock market has. It is implausible to assume that the average customer can accurately estimate the covariation of the monthly electric bill with oil prices in the international markets and the idiosyncrasies of oil prices in Hawaii. It is also implausible to assume that the average customer can accurately estimate the covariation of the monthly oil prices with the market. It is more plausible to assume that the customer consider variation in the monthly electric bill as comparable to the variation in the stock market index.

How does the customer perceive the variation of the monthly electric bill from month to month? We are not privy to each customer's perception regarding serial correlation. Therefore, I consider the two extreme cases, one with serial correlation zero and one with serial correlation one. If the customer perceives the variation of the monthly electric bill from month to month to be serially uncorrelated, then I can perform a monthly calculation and estimate the monthly premium on the electric bill as $PREM = 160 \times 0.0067 = \$1.072$. If, at the other extreme, the customer perceives the variation of the monthly electric bill from month to month to be perfectly correlated over the span of 12 months, then I can perform an annual calculation and estimate the monthly premium on the electric bill as $12 \times PREM = 12 \times 160 \times 0.08$ or $PREM = 160 \times 0.08 = \$12.86$.

Given the limited abilities of the average customer to preform intricate financial calculations based on time series of historical date and given that I am not privy to each customer's perceptions regarding serial correlation, I conclude that a fair estimate of the monthly premium lies between \$1 and \$13.

Exhibit B-6: Curriculum Vitae of Dr. George Constantinides

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June 2018

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Degrees

Oxford University, Oxford, England: BA-1970; MA-1974.
Indiana University, Bloomington, Indiana: MBA-1972; DBA-1975.

Related Experience

Fulbright Scholar, 1970. Assistant Professor, GSIA, Carnegie-Mellon University, 1974-79. Ford Foundation Visiting Assistant Professor (1978-79), Associate Professor (1979-83), Professor (1983-), University of Chicago Booth School of Business. Marvin Bower Fellow, Graduate School of Business, Harvard University, 1985-86. BP Visiting Professor, London School of Economics, 2007.

Affiliations

President (2001), president-elect (2000), vice president (1999), director (1984-86, 2002), The American Finance Association. President (1990-93), vice president (1988-90), member of the founding committee, The Society for Financial Studies. Research Associate, National Bureau of Economic Research 1989- . Director, Western Finance Association, 1989-91. Editor-in-Chief, *Foundations and Trends in Finance*, 2004-2015. Co-Editor, *Annals of Finance*, 2004-2015. Advisory Editor, World Scientific Handbook in Financial

Economics Series, 2010- ; World Scientific Series in Finance, 2010- ; Elsevier/North-Holland Handbooks in Finance Series, 2002-; *Journal of Banking and Finance* 2011-; *Mathematics and Financial Economics,* 2007-; *Quarterly Journal of Finance,* 2010-. Editor, *Critical Finance Review*, 2011-; Associate Editor, , *Review of Development Finance*, 2010-; *Ekonomia,* 1990-2014; *European Finance Review*, 1996-; *International Journal of Finance Education, 2002-*; *International Journal of Monetary Economics and Finance*, 2007-; *International Journal of Theoretical and Applied Finance*, 1997-; *International Review of Finance*, 2000-; *Journal of Finance*, 1983-00; *Journal of Financial and Quantitative Analysis*, 1984-90; *Mathematical Finance*, 1990-01; *Multinational Finance Journal*, 1997-; *Quantitative Finance*, 2001-; *Review of Derivatives Research*, 1996-; *Review of Financial Studies*, 1990-93. Chairman of the Board, University of Macedonia, 2013-2016. Member of the interim governing board, University of Cyprus, 1989-95. Chair of the advisory board, Cyprus International Institute of Management (CIIM) 2000-. Member of the advisory board, Athens Laboratory in Business Administration (ALBA) 1997-, FTSE Russell, 2009-. Trustee, the DFA Investment Trust Company 1993- and Dimensional Emerging Markets Value Fund Inc. 1993- . Director, DFA Investment Dimensions Group Inc. 1983- and Dimensional Investment Group Inc. 1993-. Director, SW7 Holdings, 2014-2017 Member of the Investment Policy Committee, Cook County IL. 2008-.

Honorary Degrees and Awards

Honorary Degree, Aristotelian University, Greece, December 2016

Honorary Degree, University of Cyprus, Cyprus, September 2011.

Honorary Degree, International Hellenic University, Greece, May 2010.

Fellow, The American Finance Association, 2002-.

Honorary Degree, University of Piraeus, Greece, June 1999.

Academy of Alumni Fellows Award, Indiana University, February 1994.

Articles

"The Supply and Demand of S&P 500 Options," *Critical Finance Review* (forthcoming, with L. Lian).

"Asset Pricing: Models and Empirical Evidence," *Journal of Political Economy* 125 (December 2017), 1782-1790.

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"What Information Drives Asset Prices?" Working paper, University of Chicago and

NBER #23689 (August 2017, with A. Ghosh).

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"Developments in Asset Pricing." Conference of the Multinational Finance Society, Limassol, April 2017.

"The Puzzle of Index Option Returns." Global Derivatives USA 2013, Chicago, IL, November 21, 2013.

"Explorations in Asset Pricing." 22nd Annual Conference on Financial Economics and Accounting (CFEA), Bloomington, Indiana, November 18, 2011.

"Asset Pricing and Macroeconomics: A Productive Collaboration," 18th Annual Conference of the Multinational Finance Society, Rome, June 27, 2011.

"The Predictability of Returns with Regime Shifts in Consumption and Dividend Growth." 14th International Conference on Macroeconomic Analysis and International Finance, University of Crete, Rethymno, May 2010.

"The Financial Crisis of 2007-2009: Lessons for Risk Management." International Conference on Applied Business and Economics (ICABE), Kavala, Greece, October 2009.

"Asset Pricing Tests with Long Run Risks in Consumption Growth." Eighth Conference on Research on Economic Theory & Econometrics (CRETE), Tinos, Greece, July 2009.

"Global Research on the Equity Premium." International Conference on the Global Economics of a Changing Environment, Athens, Greece, July 2008.

"Global Research on the Equity Premium." Fourth International Finance Conference, IFC4, Hammamet-Yasmine, Medina, Tunisia, March 2007.

"Market Organization and the Prices of Financial Assets." Thirty Seventh Annual

Conference of the Money Macro and Finance Research Group, Rethymno, Greece, September 2005.

"Global Research on the Equity Premium." Eleventh Annual Conference of the Multinational Finance Society, Istanbul, July 5, 2004.

"Rational Asset Prices." Ninth Annual Conference of the Multinational Finance Society, Cyprus, July 1, 2002.

"Rational Asset Prices." Presidential Address, American Finance Association, Atlanta, January 5, 2002.

"Asset Pricing with Heterogeneous Consumers and Limited Participation: Empirical Evidence." Intertemporal Asset Pricing Conference, hosted by CIRANO, Montreal, October 24, 1999.

"Asset Pricing with Heterogeneous Consumers and Limited Participation: Empirical Evidence." Workshop on Mathematical Finance, Vienna, September 17, 1999.

"Transaction Costs and the Pricing of Derivatives: Perspective and Recent Developments." 47th Annual Meeting of the Midwest Finance Association, Chicago, March 19, 1998.

"Transaction Costs and the Pricing of Derivatives: Perspective and Recent Developments." Fourth Annual CAP Workshop on Mathematical Finance Theory, Practice and Computation, Columbia University, October 28, 1997.

"Transaction Costs and the Pricing of Financial Assets." Fourth Annual Conference of the Multinational Finance Society, Thessaloniki, June 27, 1997.

"The Impact of Transaction Costs on Prices and Liquidity Premia when Trading is Endogenous." Conference on Recent Developments in Asset Pricing and Optimal Trading Strategies, Rutgers University, May 13, 1994.

Exhibit B-7: “Greenhouse Gas Emissions Reduction PIM (GHG)”

This exhibit supports Ulupono’s proposed Greenhouse Gas Emissions Reduction PIM (GHG Emissions Reduction PIM).

This exhibit shows: (1) the benchmark values for CO2 emissions starting with HECO’s GHG Reduction Plan starting value for 2020 with straight-line reductions to zero in 2045; (2) GHG (CO2) emissions as forecasted by the Ulupono #1 scenario based on the evolving generation mix; (3) three versions of how a GHG Emissions Reduction PIM could be paid out: a) for beating (falling below) the benchmark emissions value; (b) for falling below the previous year’s emissions; (c) receiving the incentive as in (a) until this value drops to zero and then receiving the incentive as in (b).

This last version of the incentive payment essentially is the same as (a) for beating the benchmark but in the late years (i.e., 2039 to 2045) there are relatively small incentive payments made for at least deceasing emissions year over year.

This exhibit was prepared using Ulupono #1 scenario and RIST (5/6/2020).

Greenhouse Gas Emissions Reduction PIM (GHG) (pg. 1 of 2)

	Benchmark [1]	GHG Emissions [2]	Pre-tax Incentive Payment v. Benchmark [3]	Pre-tax Incentive Payment v. Prior Year [3]	Pre-tax Blended Incentive Payment [3), 4]
	MT of CO2	MT of CO2	$MM	$MM	$MM
2021	4,956,574	5,545,179	-	1.0	1.0
2022	4,750,050	2,776,516	12.3	17.3	12.3
2023	4,543,526	2,684,566	11.8	0.6	11.8
2024	4,337,002	2,617,602	11.2	0.4	11.2
2025	4,130,478	2,520,865	10.7	0.6	10.7
2026	3,923,954	2,448,115	10.0	0.5	10.0
2027	3,717,431	2,372,466	9.3	0.5	9.3
2028	3,510,907	2,320,105	8.4	0.4	8.4
2029	3,304,383	2,229,668	7.7	0.6	7.7
2030	3,097,859	2,180,309	6.7	0.4	6.7
2031	2,891,335	2,012,626	6.6	1.3	6.6
2032	2,684,811	1,901,311	6.0	0.8	6.0
2033	2,478,287	1,769,906	5.5	1.0	5.5
2034	2,271,763	1,647,578	4.9	1.0	4.9

1) Per HECO's GHG July 2019 Reduction Plan: the 2020 goal of 5,163,098 with straight-line reductions through 2045
2) Per Ulupono Scenario #1, HECO O'ahu
3) The reward is $6/MT in 2020 and inflates at 2% per year
4) The blended incentive payment takes the comparison to the prior year if the benchmark is not beaten

Greenhouse Gas Emissions Reduction PIM (GHG) (pg. 2 of 2)

	Benchmark [1]	GHG Emissions [2]	Pre-tax Incentive Payment v. Benchmark [3]	Pre-tax Incentive Payment v. Prior Year [3]	Pre-tax Blended Incentive Payment [3], [4]
	MT of CO2	MT of CO2	$MM	$MM	$MM
2035	2,065,239	1,559,938	4.1	0.7	4.1
2036	1,858,715	1,500,910	2.9	0.5	2.9
2037	1,652,191	1,446,647	1.7	0.5	1.7
2038	1,445,667	1,406,214	0.3	0.3	0.3
2039	1,239,144	1,392,389	-	0.1	0.1
2040	1,032,620	1,387,193	-	0.0	0.0
2041	826,096	1,077,085	-	2.8	2.8
2042	619,572	867,164	-	1.9	1.9
2043	413,048	728,060	-	1.3	1.3
2044	206,524	633,887	-	0.9	0.9
2045	0	-	0.0	6.2	6.2

1) Per HECO's GHG July 2019 Reduction Plan: the 2020 goal of 5,163,098 with straight-line reductions through 2045
2) Per Ulupono Scenario #1, HECO O'ahu
3) The reward is $6/MT in 2020 and inflates at 2% per year
4) The blended incentive payment takes the comparison to the prior year if the benchmark is not beaten

Exhibit B-8: “RPS-A vs. Greenhouse Gas (GHG) Performance Incentive Mechanisms”

This exhibit supports Ulupono’s proposed RPS-A PIM.

In Decision and Order No. 36326 and recent Working Group meetings, the Commission and staff have expressed interest in a PIM targeting the Greenhouse Gas (GHG) Reduction regulatory outcome. In response, Ulupono and other stakeholders, have made efforts to develop a PIM focused on GHG reductions (GHG Emissions Reduction PIM) to address this outcome.

As mentioned in previous Working Group discussions, Ulupono is supportive of a GHG Emissions Reduction PIM as a supplement to RPS-A, noting the overlap in certain outcomes of both PIMs, such as the continued replacement of fossil fuels with renewable energy generation. In this Second Proposal Update, Ulupono proposes and discusses the Ulupono GHG Emissions Reduction PIM.

In an effort to provide a holistic perspective for each PIM, however, this exhibit describes differences between the two PIMs. These differences serve to highlight the potential limitations of a GHG Emissions Reduction PIM if adopted as a standalone PIM.

Statutory Precedent and Reporting History

One important consideration in the development of a PIM is whether metrics are available to assess performance regarding the identified outcomes through easily verifiable and reasonably available data.[150]

As described in this exhibit, the statutory precedent for the state’s Renewable Portfolio Standard (RPS) was established in 2001, complemented by a reporting history beginning in 2009. In comparison, the statutory precedent for GHG emissions began in 2007 with reporting, specific to power plants greater than or equal to 100,000 tons per year (affected sources), beginning in 2014 to Hawaii’s Department of Health (“DOH”).

Ulupono believes both the (1) longer statutory precedent and (2) five years of additional reporting history for the RPS provides the Commission with a more informed and consistent data set for renewable energy generation or RPS-A assessment.

Further, as the reporting history for GHG emissions are limited to “affected sources”, there is concern that the reported numbers may not be a true representation of the carbon emission profile for all electricity generation in Hawaii. Although this limitation may have a relatively small impact on the financial reward provided to the utility under the Ulupono GHG Emissions Reduction PIM, historical and/or recent GHG data may not be available for smaller facilities as reporting requirements are not required by DOH.

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[150] *See* Docket 2018-0088, Decision and Order 36326 at 40, filed May 23, 2019.

Emissions Counting

A focal point of Ulupono's position relates to ensuring the adoption of *all* renewables to support and accelerate the state's transition off of fossil fuel generation. Under the Ulupono GHG Emissions Reduction PIM, Ulupono considers biogenic resources such as biofuels and biomass as a renewable resource, and does not count emissions from biogenic generation in the model's forecasts and assumptions. This is consistent with Act 234, which does not count emissions from biogenic or municipal waste sources. Ulupono is also aware, however, of the significant controversy throughout the stakeholder community regarding how to treat emissions from biogenic generation. Certain stakeholders recognize these resources are renewable however still believe the emissions from biogenic resources should be counted.

If the GHG Emissions Reduction PIM was designed such that the carbon emissions from biogenic resources were counted, the utility would potentially be penalized for the carbon emissions, while also limiting Hawaii's progress towards the achievement of the state's 100% RPS. This would not be the case if the RPS-A is adopted. By design, RPS-A relies on the renewable energy definition under HRS 269-91, which includes biogas, biomass, and biodiesel. Therefore, under RPS-A, the Companies have more flexibility to accelerate the RPS in the most efficient manner possible.

Energy Efficiency and Reduced Load Impacts

Under the GHG Emissions Reduction PIM, the main objective for the utility is to reduce the amount of carbon emissions generated from the electricity sector below or beyond an established benchmark. This objective provides a variety of opportunities for the utility to achieve a sector wide reduction. Ideally, the reduction of carbon emissions is a result of more renewable energy generation coming on to the system, thereby offsetting fossil fuels. It is prudent to consider other ways the utility may be financially rewarded under the single objective of the GHG Emissions Reduction PIM, however, including factors that are beyond its control.

For example, a reduction in load due to customer energy efficiency or conservation measures, or disaster-related events (such as the current Covid-19 pandemic) would result in a reduction in carbon emissions as less generation is needed. Under the GHG Emissions Reduction PIM, the utility would be financially rewarded for such circumstances – which are beyond its control – in addition to its own performance. For RPS-A, the utility would not be rewarded for such drops in load.

Electric Vehicles

There is concern that electric vehicles (EV) may be disincentivized under the GHG Emissions Reduction PIM, as the increase in load from charging EVs will have a related increase in carbon emissions until the utility can generate all electricity with renewable energy. This limitation may impact the utility's desire to invest in and support EV initiatives that would have otherwise provided benefits to the system and customers, including much lower emissions from the transportation sector that more than offset increases (for charging) from the electric sector.

Under RPS-A, EVs would only be disincentivized if the increased load was being served by oil/petroleum generation (rather than renewables or less curtailment of renewables). RPS-A also provides the opportunity for the utility to embrace EVs as a grid supportive tool, as EVs can be used to support the accelerated deployment of renewable energy through demand response functions, storage capabilities, Time of Use (TOU) charging rates, and vehicle-to-grid potential.

Accounting Methodology

For carbon emissions there is significant debate and controversy over the methodology – not only biogenic vs. non-biogenic but also point source vs. total life cycle "accounting" for the carbon emissions In comparison, the only potential debate over the RPS is whether the focus should be on the statutory RPS definition or a corrected RPS which includes customer-sited resources in the denominator (rather than dividing by net sales).

For all of these reasons, Ulupono has an overall preference for the RPS-A PIM but is also willing to support a GHG or carbon emissions reduction PIM as a supplement to the RPS-A.

RPS-A vs. Greenhouse Gas (GHG) Performance Incentive Mechanisms

Topic	GHG (CO2) PIM	RPS-A PIM
Statutory Precedent	Act 234 – Establishing a statewide GHG program (**2007**), and Act 15 (**2018**) – Carbon Neutrality by 2045 (for all sectors)	Act 272 – RPS Law (**2001**) set voluntary targets for local RE generation, Act 155 (**2009**) - expanded RPS target to 40% by 2030, and Act 97 (**2015**) - increased RPS to 100%
Reporting History	GHG Emission Reduction Plans have been required to be submitted to DOH for "affected sources" (greater than or equal to 100,000 tons per year) since **2014**, pursuant to HAR Chap. 11-60.1-204. (*The Companies have been reporting to the EPA since **2011** for operating year 2010 – DOH copied on EPA reporting)	First docketed RPS Report (Docket No. 2007-0008 – RPS Law Examination) was filed by the Companies in **June 2009.** Reporting is required annually, pursuant to the Framework for Renewable Portfolio Standards issued on December 19, 2008.
Biofuels, Biomass, and Biogenic Emissions	If biogenic emissions "count", biofuels, biomass, and waste generation are effectively penalized	Biofuels, biomass and waste generation are considered "renewable" under statute and will count toward the RPS goal
Energy Efficiency (EE) Reduced Load	Utility rewarded for efforts beyond its control (ex. Hawaii Energy initiatives, customer efficiency and conservation choices, and disaster related reduced load)	Utility not rewarded for EE measures or decreased load/conservation
Electric Vehicles (EV)	Adoption of EVs may be disincentivized. Utility will be penalized for the additional load to charge EVs until the grid is 100% renewable, as a portion of the system's generation will come from fossil fuels.	Adoption of EVs not disincentivized. EVs used in grid supportive measures (DR, V2G, TOU, etc.) could increase RPS.
Methodology Stakeholder Alignment	Biogenic v. Non-biogenic Point Source v. Total Life Cycle	Statutory v. Corrected RPS Clear definition and alignment on definition of "renewables"

Exhibit B-9: “Ulupono Electrification of Transportation (EoT) PIM”

This exhibit supports Ulupono’s proposed Electrification of Transportation (“EoT”) PIM (“Ulupono EoT PIM”).

This exhibit shows the number of EVs modeled in the Ulupono #1 scenario with an EV adoption rate very similar to that in Hawaiian Electric’s Electrification of Transportation Roadmap document (see Fig. 19, “Hawaiian Electric’s personal light-duty EV adoption forecast, Oahu, 2010 – 2045”).

The electrical load from charging those EVs then translates into two estimates for the EoT incentive payment: (1) one that assumes all EV charging is from unmetered stations (1 cent per kWh); and (2) one that assumes 95% unmetered, 5% metered split in the kWhs, with metered kWh rewarded at 3 cents per kWh. The incentive value per kWh is inflated at 2% per year.

The total incentive value starts off at very low value and does not become significant until EV penetration is modeled to pick up to significant levels in the later years.

Nevertheless, supportive actions by the utility (strategic siting of charging stations or expedited interconnections of third party charging stations) could plausibly accelerate this adoption curve.

This exhibit was prepared using Ulupono #1 scenario and RIST (5/6/2020).

ulupono Roland Berger

Electrification of Transportation (EoT) PIM (pg. 1 of 2)

	Electric Vehicles	EV Load [1]	Pre-tax Incentive Payment at \$0.01/kWh [2]	Metered EV Load [3]	Non-Metered EV Load [3]	Pre-tax Incentive Payment [2] [4]
	Thousands	GWh	\$MM	GWh	GWh	\$MM
2021	14	31.0	0.3	1.5	29.4	0.3
2022	16	36.2	0.4	1.8	34.4	0.4
2023	20	44.4	0.5	2.2	42.2	0.5
2024	24	53.0	0.6	2.7	50.4	0.6
2025	28	63.9	0.7	3.2	60.7	0.8
2026	34	75.7	0.9	3.8	71.9	0.9
2027	39	88.8	1.0	4.4	84.4	1.1
2028	47	105.3	1.2	5.3	100.1	1.4
2029	55	122.8	1.5	6.1	116.7	1.6
2030	63	142.2	1.7	7.1	135.1	1.9
2031	73	163.6	2.0	8.2	155.4	2.2
2032	84	189.8	2.4	9.5	180.3	2.6
2033	96	215.4	2.8	10.8	204.6	3.1
2034	109	244.8	3.2	12.2	232.6	3.6

1) Per Ulupono Scenario #1, HECO O'ahu
2) Incentive payments are inflated at 2% per year
3) Assumes 5% of load is metered
4) Incentive payment is \$0.03/kWh for metered EV load, \$0.01/kWh for non-metered EV load

Electrification of Transportation (EoT) PIM (pg. 2 of 2)

	Electric Vehicles	EV Load [1]	Pre-tax Incentive Payment at \$0.01/kWh [2]	Metered EV Load [3]	Non-Metered EV Load [3]	Pre-tax Incentive Payment [2][4]
	Thousands	GWh	\$MM	GWh	GWh	\$MM
2035	123	277.6	3.7	13.9	263.8	4.1
2036	137	309.3	4.2	15.5	293.8	4.7
2037	154	346.6	4.9	17.3	329.3	5.3
2038	173	389.5	5.6	19.5	370.1	6.1
2039	195	438.3	6.4	21.9	416.4	7.0
2040	221	497.2	7.4	24.9	472.4	8.1
2041	251	566.2	8.6	28.3	537.9	9.4
2042	285	641.1	9.9	32.1	609.0	10.9
2043	322	724.4	11.4	36.2	688.2	12.6
2044	363	816.9	13.1	40.8	776.1	14.5
2045	407	917.0	15.0	45.9	871.2	16.5

1) Per Ulupono Scenario #1, HECO O'ahu
2) Incentive payments are inflated at 2% per year
3) Assumes 5% of load is metered
4) Incentive payment is \$0.03/kWh for metered EV load, \$0.01/kWh for non-metered EV load

Exhibit B-10: "EoT BCA: Carbon Emission Valuation"

This exhibit shows the cost of increased carbon emissions over time due to increased load from EVs, as well as the value of the proposed EoT PIM incentive and the cost of avoided carbon emissions from not burning gasoline.

The value of reducing carbon emissions from gasoline exceeds both the PIM incentive value and the increased emissions cost from charging by an order of magnitude. This would be true for any reasonable cost used for carbon.

The table on the graph indicates the value of carbon reduction from avoided gasoline per kWh delivered to an EV at both the $6 per MT (GHG Emissions Reduction PIM valuation of carbon) and $42 per MT (full valuation of carbon reduction) levels. With the value of avoided carbon at 1 cent to 7.1 cents per EV kWh, the value of avoided carbon alone can justify the proposed PIM incentive value of 1 cent per kWh for non-metered and 3 cents per kWh for metered charging stations, especially since nearly all charging stations in Hawaii are not presently metered.

EoT BCA: Carbon Emission Valuation

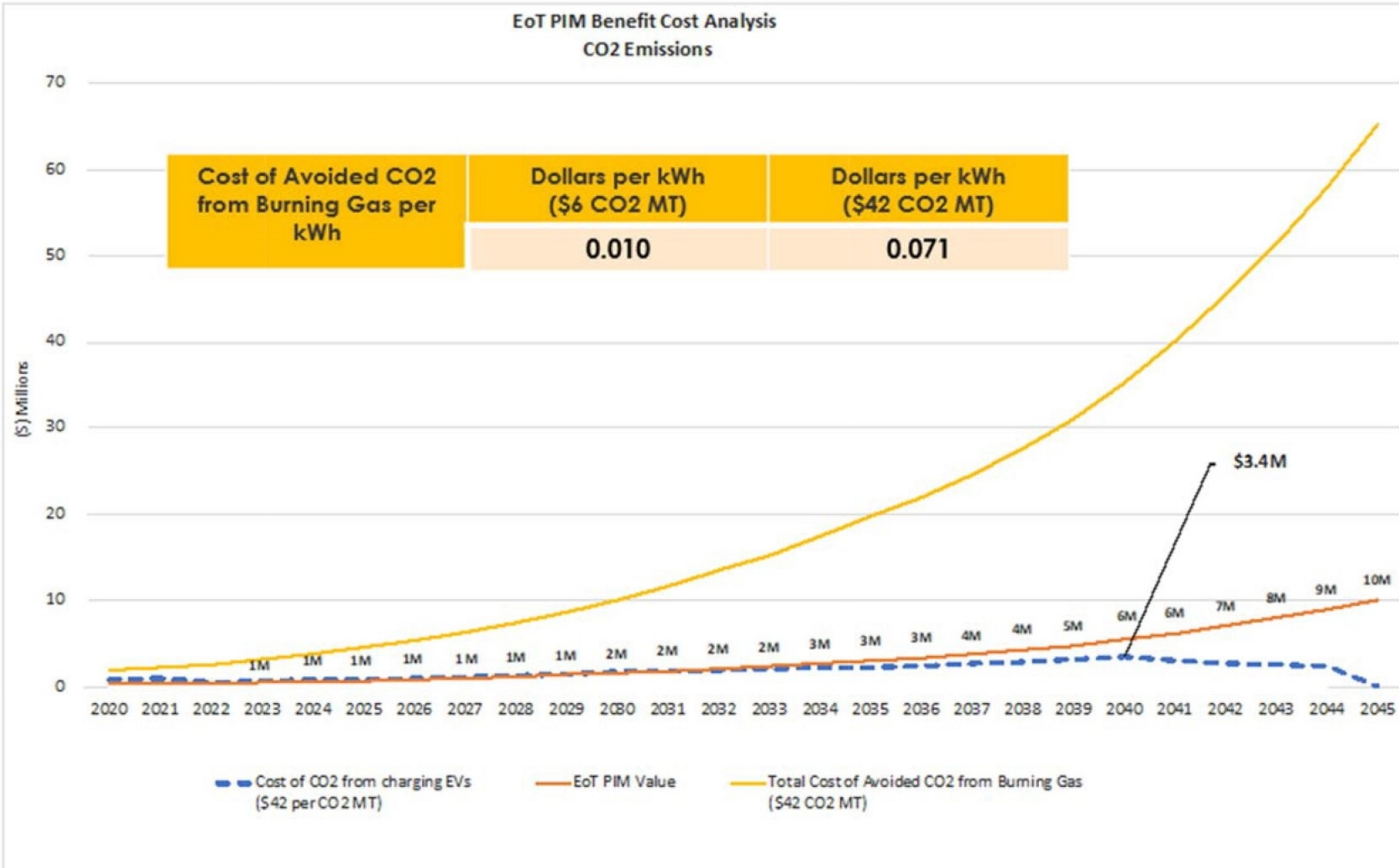

Exhibit B-11: "EoT BCA – Customer Bill Reduction Through Decoupling"

When the Commission instituted decoupling in 2010,[151] significant load from electric vehicles was likely not seriously considered. The rise of EV ownership, both to date and projected, will be an unplanned-for boon to ratepayers by shifting some energy load from the transportation sector to the electric sector. All else equal, via decoupling this increase in load should put downward pressure on customer bills by spreading fixed costs over more kWh of sales. This effect has real financial value to all ratepayers whether they own an EV or not.

To calculate this value, Ulupono developed a proxy for fixed costs from the RIST by adding Approved Base Revenues and ARA adjustments and subtracting Variable Generation operations and maintenance (O&M) expenses. Dividing this amount by net load (including EVs but net of customer generation consumed behind the meter) gives a fixed cost contribution from each kWh sold.

Multiplying that number by the EV load, then, provides the total amount of fixed cost coverage provided by sales of electricity to EV owners.

These fixed cost contributions are the amounts that ratepayers would have had to cover (through higher rates) if not for the contribution from EV drivers. Ulupono estimates this amount to be $3.1 million in 2021 rising to $109.7 million in 2045 ($66.9 million in 2020 dollars)..

The fixed cost contribution per kWh starts at 9.9 cents in 2021 and declines (when deflated to 2020 dollars) to 7.3 cents in 2045 – the lower value due to fossil plant retirements and the increasing share of costs that comes from variable costs such as PPAs. With a suggested PIM value of 1 cent per kWh for non-metered EV charging station sales and 3 cents for metered stations, the value provided to ratepayers (at the high-end of about 10.3 cents per kWh in 2030 – but in 2020 dollars) is significantly higher than the cost of the incentive. Even if one were to assume that the EV load cut the net fixed cost coverage value in half to 5.1 cents (assuming fixed costs would go up to service charging stations) the benefit to ratepayers still exceeds the cost of the PIM.

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[151] *See* Docket No. 2008-0274 Instituting a Proceeding to Investigate Implementing a Decoupling Mechanism for the Hawaiian Electric Companies, Final Decision and Order and Dissenting Opinion of Leslie H. Kondo, Commissioner, filed August 31, 2010.

EoT BCA – Customer Bill Reduction Through Decoupling

	Proxy for Fixed Costs	Fixed Cost Contribution from EVs	Fixed Cost Cont. from EVs / kWh	Fixed Cost Cont. from EVs / kWh (2020 $)
FY2020	$ 716,530,337	$ 2,641,494	$ 0.1013	$ 0.1013
FY2021	$ 692,967,718	$ 3,072,818	$ 0.0992	$ 0.0973
FY2022	$ 705,218,907	$ 3,708,729	$ 0.1025	$ 0.0985
FY2023	$ 718,683,693	$ 4,699,188	$ 0.1058	$ 0.0997
FY2024	$ 732,038,199	$ 5,765,725	$ 0.1088	$ 0.1005
FY2025	$ 745,927,572	$ 7,198,354	$ 0.1126	$ 0.1020
FY2026	$ 719,760,520	$ 8,325,022	$ 0.1099	$ 0.0976
FY2027	$ 733,222,612	$ 10,080,544	$ 0.1135	$ 0.0988
FY2028	$ 746,768,347	$ 12,279,689	$ 0.1166	$ 0.0995
FY2029	$ 761,082,575	$ 14,901,224	$ 0.1213	$ 0.1015
FY2030	$ 774,346,902	$ 17,787,649	$ 0.1251	$ 0.1026
FY2031	$ 762,125,646	$ 20,212,644	$ 0.1236	$ 0.0994
FY2032	$ 777,391,399	$ 23,694,255	$ 0.1248	$ 0.0984
FY2033	$ 792,906,778	$ 27,349,593	$ 0.1270	$ 0.0982
FY2034	$ 807,723,618	$ 31,511,380	$ 0.1287	$ 0.0975
FY2035	$ 822,706,508	$ 36,447,713	$ 0.1313	$ 0.0975
FY2036	$ 805,952,417	$ 39,621,583	$ 0.1281	$ 0.0933
FY2037	$ 820,677,231	$ 45,057,953	$ 0.1300	$ 0.0928
FY2038	$ 835,352,950	$ 51,301,905	$ 0.1317	$ 0.0922
FY2039	$ 850,031,274	$ 58,495,408	$ 0.1335	$ 0.0916
FY2040	$ 864,310,112	$ 66,733,958	$ 0.1342	$ 0.0903
FY2041	$ 882,593,617	$ 75,600,267	$ 0.1335	$ 0.0881
FY2042	$ 842,055,757	$ 79,075,866	$ 0.1233	$ 0.0798
FY2043	$ 858,147,636	$ 88,361,293	$ 0.1220	$ 0.0774
FY2044	$ 873,460,526	$ 98,392,177	$ 0.1204	$ 0.0749
FY2045	$ 888,634,249	$ 109,741,135	$ 0.1197	$ 0.0729

Exhibit B-12: "Stats & Sources for PIM Benefit Cost Analysis"

Stats & Sources for PIM Benefit Cost Analysis

- **RPS-A PIM**
  - **Carbon Dioxide 2018 Power Industry Emission Estimates, Energy Information Administration**
    - **Petroleum** - 1.79 pounds of CO_2 per kWh
  - **2018 Electric Power Generation by Source (MWh), Energy Information Administration**
    - **Petroleum** – 6,748,947 MWh
- **EoT PIM**
  - **Carbon Dioxide Coefficient for Gasoline, Energy Information Administration**
    - 19.6 pounds of CO_2 per gallon
  - **Average kWh per mile for cars in Hawaii, SWITCH Data**
    - 0.25 kWh per mile
  - **Average fuel efficiency for cars in Hawaii, DBEDT Databook**
    - 21 MPG (2018)
- **GHG PIM**
  - **16% reduction requirement**: **Act 234, HAR 11-60.1-204(c).** Unless substantiated by the owner or operator of an affected source and approved by the director to be unattainable pursuant to the GHG control assessment described in subsection 11-60.1-204(d), each GHG emission reduction plan shall establish a minimum facility-wide GHG emissions cap in tons per year CO_2e, to be achieved by 2020 and maintained thereafter. **The minimum facility-wide GHG emissions cap shall be sixteen percent (16%) below the facility's total baseline GHG emission levels. (2014)**

Exhibit B-13: “Shared Savings Mechanism: Renewable PPA and Grid Services/NWA”

This exhibit shows: (1) new renewable PPA generation forecasted to come on line by the Ulupono #1 scenario; (2) an estimate of the first 24 months of PPA expense from those projects; (3) total renewable PPA savings assuming that PPAs, come in, on average 10% under HPUC target price (the price to beat to achieve shared savings); (4) new grid services capacity that comes on-line each year based on a high-level, preliminary forecast provided by HECO to assist the working group process; (5) grid services benefit estimated to be 20% more than the cost of services; and (6) an estimate of the value of a shared savings mechanism which is the sum of 30% of #3 and 30% of #5.

This provides an estimate of a SSM mechanism in which the utility shares 30% in two years’ worth of savings from both competitive procurements of utility scale renewable energy and from grid services/non-wires alternatives (NWA).

The SSM is meaningful in the early years in which large competitive procurements are taking place, then it moderates for a time before increasing again as procurements increase to meet an ever increasing RPS (for clarity, this depiction of Ulupono’s proposed SSM does not directly model the SSMs employed in the ongoing and current utility competitive procurements, i.e., the Phase 1 and Phase 2 RFPs in Docket No. 2017-0352)).

This SSM would be available only for renewable PPAs and grid services/NWA that are competitively procured by the utility.

This exhibit was prepared using Ulupono #1 scenario and RIST (5/6/2020).

Shared Savings Mechanism: Renewable PPA and Grid Services/NWA (pg. 1 of 2)

	New Renewable PPA Generation (Year 1 only) [1]	Renewable PPA Expense (First 24 months of PPA) [2]	Total Renewable PPA Savings [3]	New Grid Services Capacity [1]	Grid Services Benefit (First 24 months) [4]	Pre-Mechanism Payment [5]
	GWh	$MM	$MM	MW	$MM	$MM
2021	45.1	4.5	50	1.6	1.8	45.1
2022	144.0	14.4	20	2.3	5.0	144.0
2023	105.3	10.5	30	1.7	3.7	105.3
2024	10.7	1.1	20	1.7	0.8	10.7
2025	10.5	1.1	-	0.7	0.5	10.5
2026	9.2	0.9	30	1.1	0.6	9.2
2027	7.9	0.8	-	1.1	0.6	7.9
2028	7.8	0.8	50	1.8	0.8	7.8
2029	7.7	0.8	-	1.9	0.8	7.7
2030	7.6	0.8	50	1.9	0.8	7.6
2031	34.5	3.4	-	1.9	1.6	34.5
2032	61.5	6.1	50	2.0	2.4	61.5
2033	60.7	6.1	-	2.0	2.4	60.7
2034	60.0	6.0	50	2.1	2.4	60.0

1) Per Ulupono Scenario #1, HECO O'ahu
2) Estimate of the first 24 months of the contract
3) Assumes savings of 10% under HPUC target
4) Assumes cost of $156/kW and total benefit of 1.2 times project cost
5) Assumes sharing of 30% of savings achieved and inflation of 2%/year

Shared Savings Mechanism: Renewable PPA and Grid Services/NWA (pg. 2 of 2)

	New Renewable PPA Generation (Year 1 only) [1]	Renewable PPA Expense (First 24 months of PPA) [2]	Total Renewable PPA Savings [3]	New Grid Services Capacity [1] [6]	Grid Services Benefit (First 24 months) [4]	Pre-Mechanism Payment [5]
	GWh	$MM	$MM	MW	$MM	$MM
2035	207	59.3	5.9	-	2.1	2.4
2036	23	66.6	6.7	-	-	2.0
2037	23	51.1	5.1	-	-	1.5
2038	24	27.5	2.7	-	-	0.8
2039	23	27.6	2.8	-	-	0.8
2040	24	27.7	2.8	-	-	0.8
2041	944	104.4	10.4	-	-	3.1
2042	1,005	193.3	19.3	-	-	5.8
2043	793	187.8	18.8	-	-	5.6
2044	714	172.0	17.2	-	-	5.2
2045	651	173.3	17.3	-	-	5.2

1) Per Ulupono Scenario #1, HECO O'ahu
2) Estimate of the first 24 months of the contract
3) Assumes savings of 10% under HPUC target
4) Assumes cost of $156/kW and total benefit of 1.2 times project cost
5) Assumes sharing of 30% of savings achieved and inflation of 2%/year
6) HECO forecast ended in 2034, assumes no new grid services capacity after

Exhibit B-14: “RPS-A, EoT Incentive, and Shared Savings Mechanism impact, under the Ulupono Initiative Second Proposal Update”

This exhibit shows the stacked values of the PIMs from Ulupono’s first proposal update but with impacts from the updated RIST financial model.

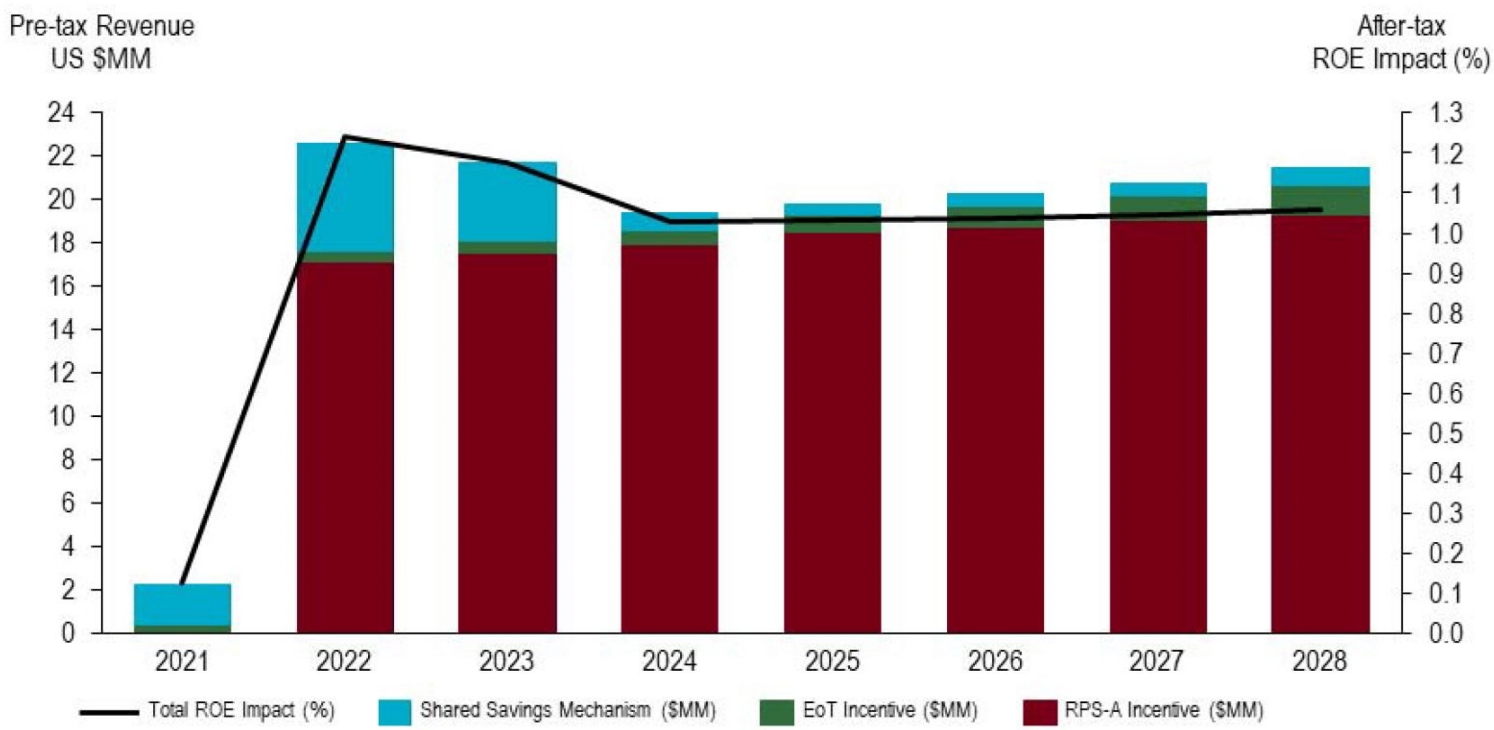
The left-hand Y axis shows pre-tax revenues as this is what the ratepayer experiences. The right-hand Y axis shows after-tax ROE impact as this is what the utility and its shareholders experience.

The maximum ROE impact is less than 1.3 percentage points of ROE. While this may be sufficient to incentivize the desired level of change, it is also less than the 2% points of ROE cited by several parties in the docket as the target level of total, potential PIM impact.

As the SWITCH optimizer requires the achievement of the corrected (rather than statutory) RPS goals in 2020, 2030, 2040, and 2045 in choosing the most cost-effective resource plan, the level of performance shown in this chart can be thought to be what is possible with a very aggressive and dedicated pursuit of the RPS and EoT goals—not a true maximum PIM value, but definitely representative of exemplary performance.

This exhibit was prepared using Ulupono #1 scenario and RIST (5/6/2020).

RPS-A, EoT Incentive, and Shared Savings Mechanism impact, under the Ulupono Initiative Second Proposal Update



1) Per Ulupono Scenario #1, HECO O'ahu in the RIST model (version 5/06)
2) PIM rewards are quoted in 2020 dollars and inflated at the rate of the ARA, which is 2% per year
- RPS-A assumes $10/MWh reward for exceeding annual corrected RPS goals, inflated at 2%
- EoT assumes incentive of $0.03/kWh for metered and $0.01/kWh for non-metered EV load, 5% of EV stations are assumed to be metered charging stations
- Shared Savings assumes 10% improvement in PPA cost and benefit/cost ratio of 1.2 for grid services. Incentive payment equals 30% of savings over first 24 months of contract

Exhibit B-15: "RPS-A, EoT Incentive, GHG and Shared Savings Mechanism impact, under the Ulupono Initiative Second Proposal Update"

This exhibit shows the stacked values of the PIMs from Ulupono's first proposal update with the addition of a GHG emissions reduction PIM but with impacts from the updated RIST financial model.

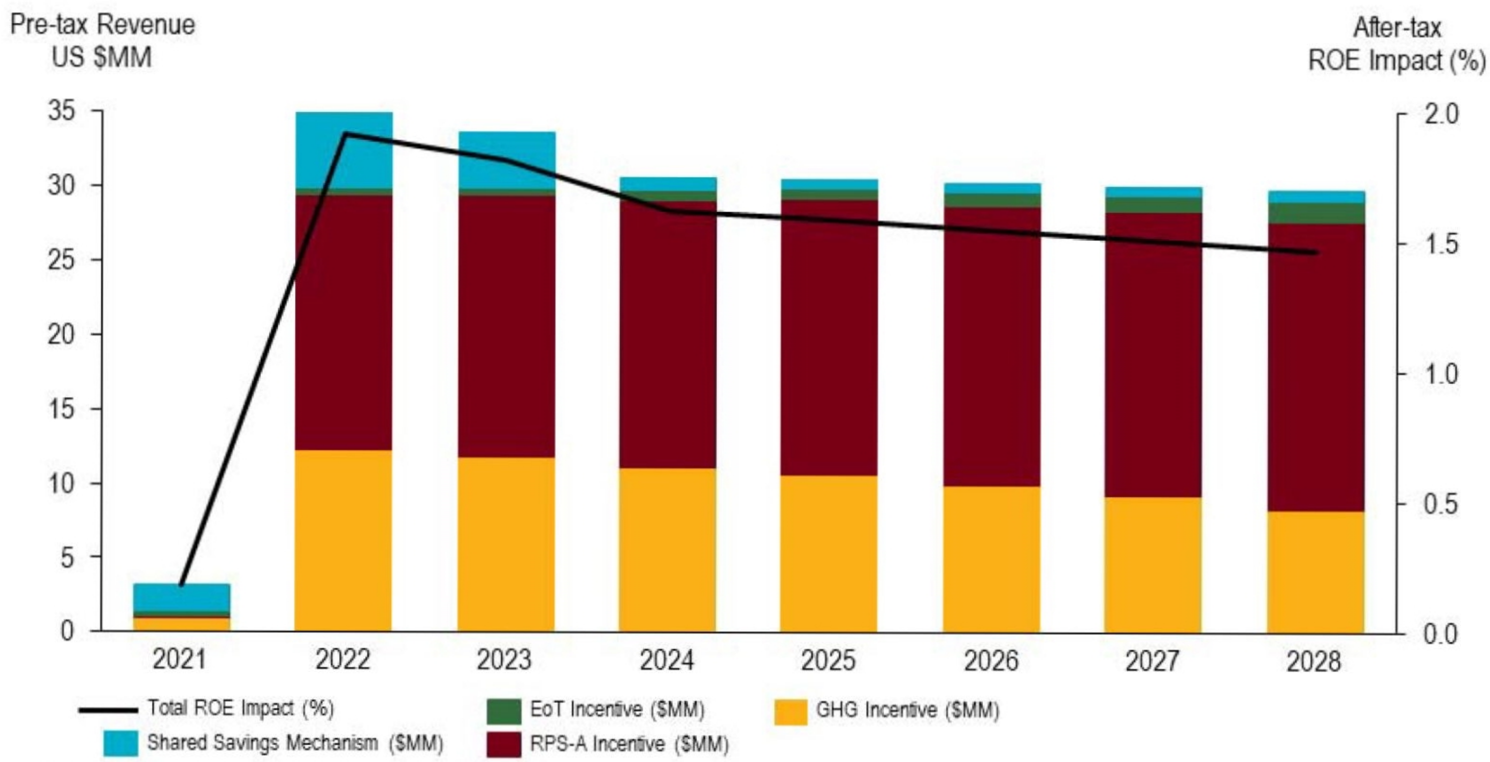
The left-hand Y axis shows pre-tax revenues as this is what the ratepayer experiences. The right-hand Y axis shows after-tax ROE impact as this is what the utility and its shareholders experience.

The maximum ROE impact is roughly 2 percentage points of ROE. This is equivalent to the 2% points of ROE cited by several parties to the docket as the target level of total, potential PIM impact.

As the SWITCH optimizer requires the achievement of the corrected RPS goals in 2020, 2030, 2040, and 2045 in choosing the most cost-effective resource plan, the level of performance shown in this chart can be thought to be what is possible with a very aggressive and dedicated pursuit of the RPS, GHG emission reduction, and EoT goals – not a true maximum PIM value, but definitely representative of exemplary performance.

This exhibit was prepared using Ulupono #1 scenario and RIST (5/6/2020).

RPS-A, EoT Incentive, GHG and Shared Savings Mechanism impact, under the Ulupono Initiative Second Proposal Update



1) Per Ulupono Scenario #1, HECO O'ahu in the RIST model (version 5/06)
2) PIM rewards are quoted in 2020 dollars and inflated at the rate of the ARA, which is 2% per year
- RPS-A assumes $10/MWh reward for exceeding annual corrected RPS goals, inflated at 2%
- EoT assumes incentive of $0.03/kWh for metered and $0.01/kWh for non-metered EV load, 5% of EV stations are assumed to be metered charging stations
- GHG assumes incentive of $6/MT below the benchmark or incremental improvement from prior year
- Shared Savings assumes 10% improvement in PPA cost and benefit/cost ratio of 1.2 for grid services. Incentive payment equals 30% of savings over first 24 months of contract

Exhibit B-16: “Updated Reported Metrics”

This document was submitted with Ulupono’s First Proposal Update filed Jan. 15, 2020, has not been modified, and is included for convenience.

“Updated Reported Metrics”

Outcome	Proposed Reported Metric
Affordability	The kilowatt (“kW”) weighted average price of renewables compared to the avoided cost of fossil fuels.
Capital Formation	Total market value (or book value, if necessary) of all IPP owned assets and infrastructure compared to the total market value of all utility owned assets and infrastructure. If market and/or book value of IPP assets is not accessible, an acceptable (although less useful) alternative would be to report the total percentage of average customer bills attributable to IPPs (PPAs, NWAs, other grid services, etc.) as compared to the percentage attributable to utility owned assets.
Capital Formation	Credit rating, including directionality based on outlook or forecast from credit rating agencies.
Cost Control	The kW weighted average price of renewables compared to the avoided cost of fossil fuels.
Cost Control	Rate of annual growth for overall authorized revenues compared to inflation. This is not intended to replicate the ARA but to capture ARA interaction with MPIR, Z-Factor, etc. The rate may exceed inflation minus customer dividend. The primary purpose is to capture actual revenue increase after all adjustments due to PBR mechanisms are accounted for.
Customer Engagement	The number of customers participating in each type of energy program including: Net Energy Metering, Net Energy Metering Plus, Customer Grid-Supply, Customer-Grid Supply Plus, Customer Self-Supply, Community Based Renewable Energy, time-of-use rates (including EV TOU rates), demand response, grid-interactive water heaters, and other similar programs and activities (collectively, “programs”).
Customer Engagement	Acceptance rate of applicants to each of the programs.
Customer Equity	Total number and percentage of LMI participation in programs (as defined under the Customer Engagement outcome).
Customer Equity	Total value of subsidization by ratepayers that benefit other classes of ratepayers. It is acknowledged this may be difficult to calculate. The focus is on capturing the value of cross-subsidization.
DER Asset Effectiveness	Total value of NWAs contracted for by the utility (rather than proposed) as compared to the avoided cost of conventional non-NWA solutions, on an annual and cumulative basis.
Electrification of Transportation	For purposes of EoT PIM, actual metered kWh to EVs plus total estimated kWh to EVs. Estimated GHG avoidance based on average ICEV efficiency. (See formula below in second GHG Reduction reported metric description).
Electrification of Transportation	Total number of registered EVs, and percentage rate of growth or increase in number of registered EVs, both on an annual basis. If possible, EVs as a percentage of new car sales, on calendar year annual basis.
GHG Reduction	Estimated avoided GHG emissions from use of renewable energy as compared to use of fossil fuel (on fuel substitution not lifecycle basis).

GHG Reduction	GHG emission reductions calculated pursuant to the following formula: Total kWhs consumed by EVs times average EV miles per kWh, times average ICEV gallons per miles, times GHG emissions per gallon of fuel.
Grid Investment Efficiency	Percentage of customers on circuits that have reached maximum hosting capacity, and change in percentage from prior year.
Resilience	Average or median length of time each class of critical care facilities (e.g. fire departments, hospitals, clinics) can maintain power without access to grid or utility power. As this will require data from non-utility sources it will need support of non-utility actors (State, Board of Water Supply, hospitals, wastewater treatment plants, etc.).
Resilience	Vulnerability assessments of quantified forecasted impacts to poles, wires, generation facilities and related infrastructure, as measured, for example, by the estimated loss of load or service due to (i) downed transmission or distribution circuit poles and lines from specified ranges of wind speeds, or (ii) damage to coastal utility infrastructure from a specified ranges of storm surge.

ATTACHMENT C
FINANCIAL IMPACTS OF ULUPONO'S PBR PROPOSALS EXHIBITS

Exhibit C-1: "Revenue Breakdown: Ulupono Initiative Second Proposal Update v. Status Quo"

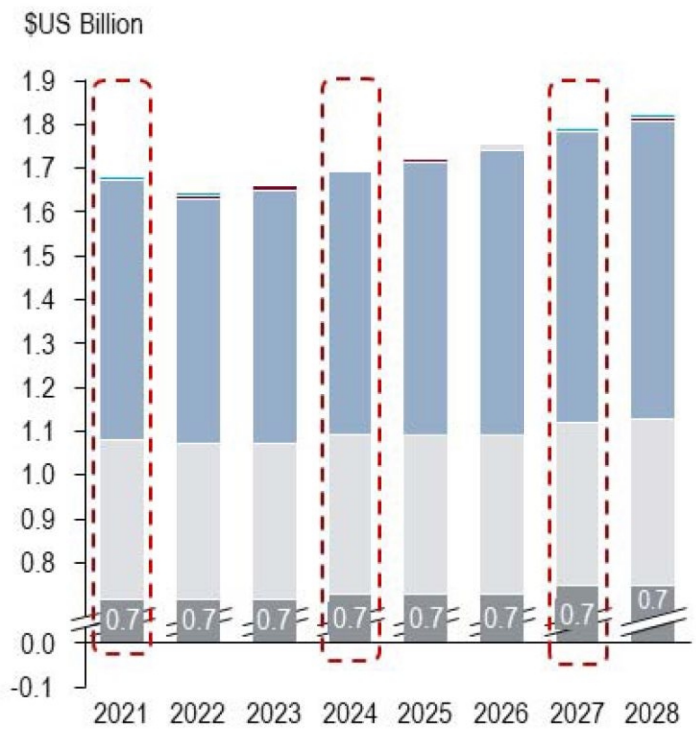
This exhibit shows the revenue breakdown for both the status quo regulatory structure and a PBR structure based on Ulupono's second proposal update – both using the Ulupono #1 scenario for inputs.

Note that the ESM is shown as a thin bar at the bottom of the columns in years in which the ESM would reduce revenues by sharing back to ratepayers.

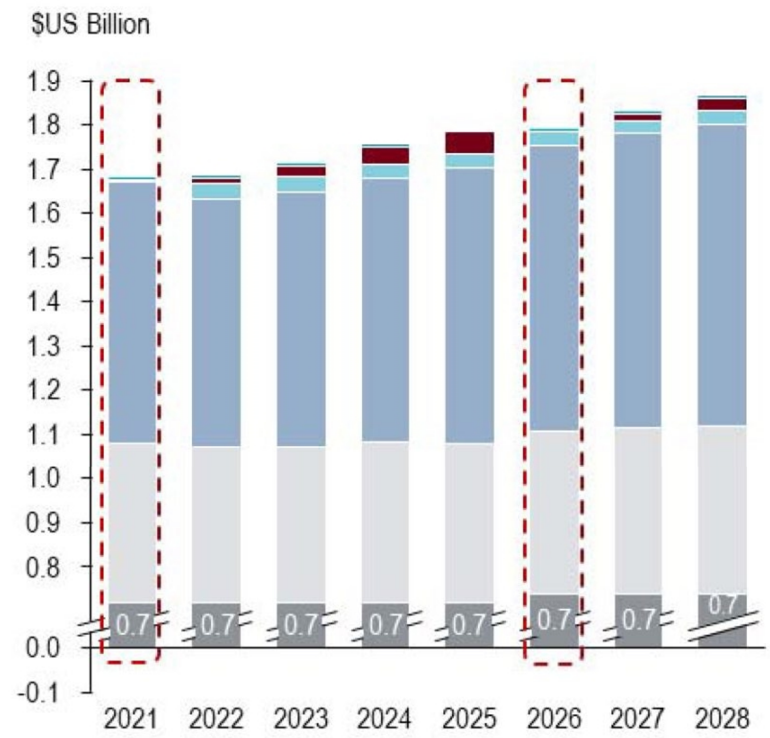
This exhibit was prepared using Ulupono #1 scenario and RIST (5/6/2020).

Revenue Breakdown: Ulupono Initiative Second Proposal Update v. Status Quo

Status Quo 1) [2021-2028, US$ Billion]



Ulupono Initiative Second Proposal Update 2) [2021-2028, US $Billion]



Allowed Base Revenues ECRC PPAC MPIR PIMs ARA / RAM ESM Pole Revenue Rate Resetting

1) Results reflect the Status Quo under the Ulupono Scenario #1 HECO O'ahu in the RIST model (version 5/06) 2) Results reflect Ulupono Initiative Second Proposal Update using the Ulupono Scenario #1, HECO O'ahu in the RIST model (version 5/06) 3) PIMs include RPS-A, EoT, GHG and Shared Savings Mechanism, 3) ARA utilizes RPI of 2%, X Factor of 0% and Consumer Dividend of 0.22%

Exhibit C-2: “HECO financial metrics and impacts on residential customers”

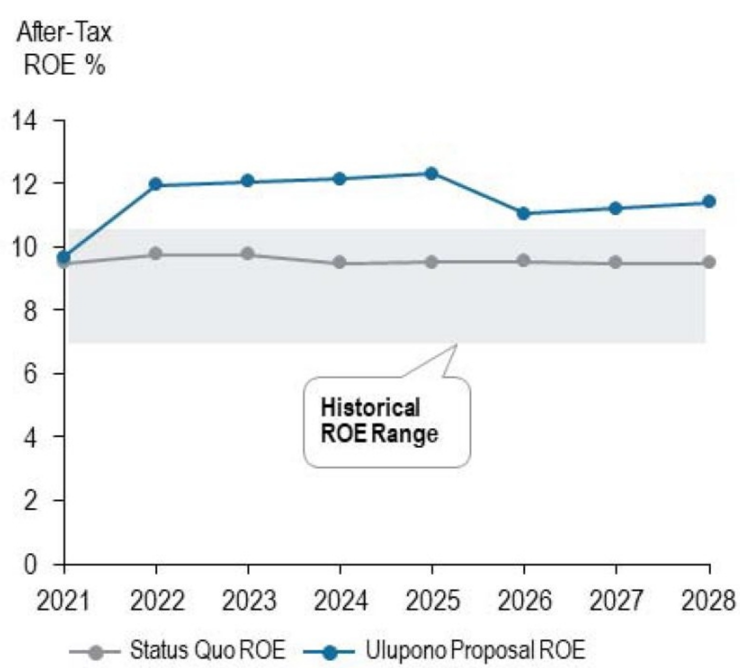
This exhibit shows the ROE and bill impacts under the status quo regulatory structure and a PBR structure based on Ulupono’s second proposal update – both using the Ulupono #1 scenario for inputs. ROE under Ulupono’s proposal is forecasted to be higher than under the status quo and higher than historical ROE.

Similarly, growth in bills will be higher but the customer is getting better performance for those slightly higher bills. Note that $/kWh is calculated as total revenues divided by total kWh – essentially an average of all rates – not necessarily the residential rate. In addition, the CAGR shown on this exhibit includes 2% inflation.

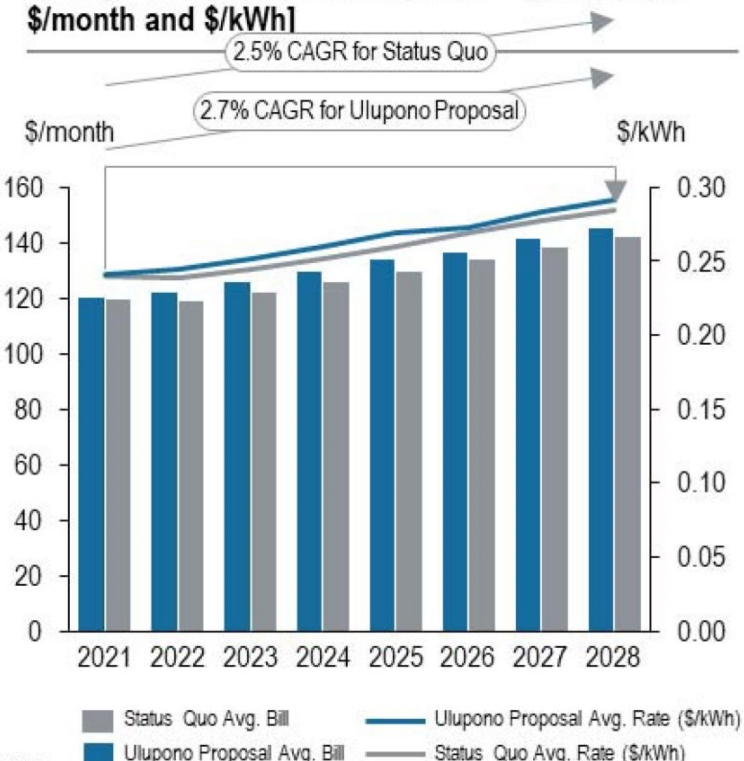
This exhibit was prepared using Ulupono #1 scenario and RIST (5/6/2020).

HECO financial metrics and impacts on residential customers

Return on Equity [1] [2] [2021-2028, %]



Average Residential Bill and Costs [2] [2021-2028, $/month and $/kWh]



Note: Reflects results from Ulupono Scenario #1 HECO Oahu in the RIST model (version 5/06)
1) Shows the range of HECO's historical ROE from 2010-2018
2) Ulupono Proposal includes Ulupono Initiative Proposed PIMs, as described in Second Proposal Update

Exhibit C-3: “Debt metrics demonstrate HECO will maintain credit rating”

This exhibit shows the four Moody’s quantitative credit rating factors over time comparing status quo to the Ulupono proposal.

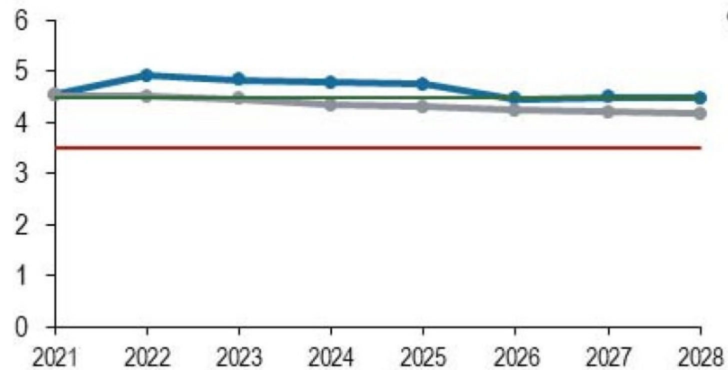
The four quantitative factors indicate that HECO should (based on the 40% weight to quantitative metrics) maintain its credit rating.

Note that (CFO pre-working capital – dividends)/Debt looks unusually poor because the RIST model maintains a fixed capital structure and returns excess equity to shareholders via dividends – thus overstating dividends. The Debt/Capitalization ratio in negatively impacted by the rise in imputed debt from purchased power agreements.

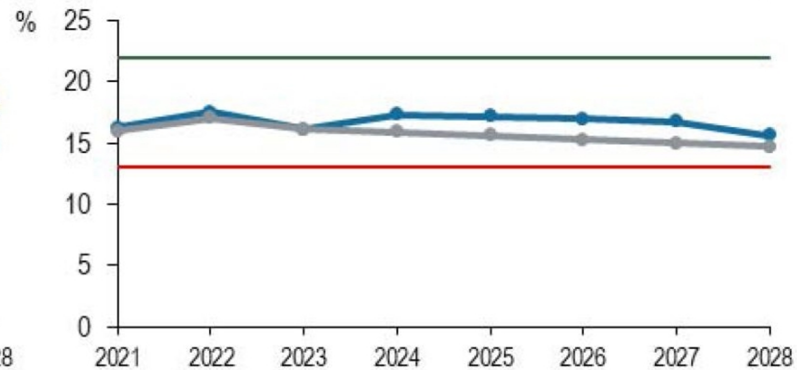
This exhibit was prepared using Ulupono #1 scenario and RIST (5/6/2020).

Debt metrics demonstrate HECO will maintain credit rating

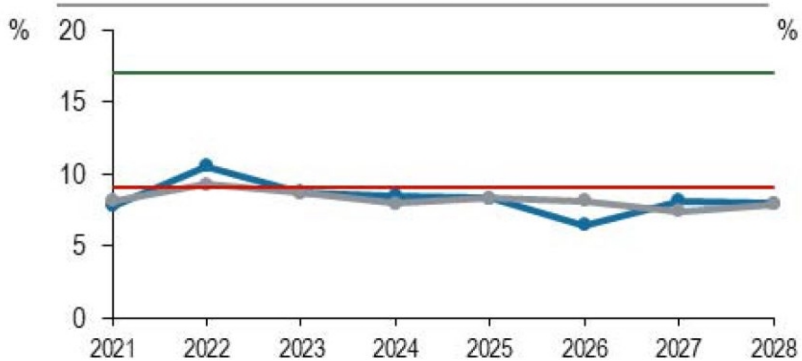
(CFO[1] pre-Working Capital + Interest) / Interest [2021-2028]



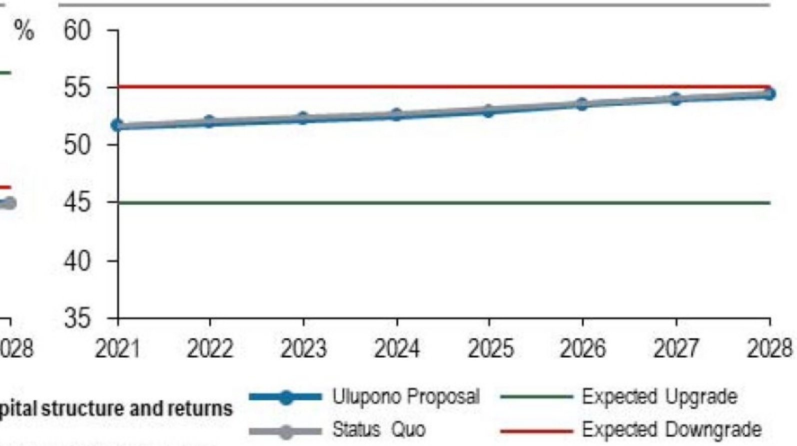
CFO pre-Working Capital / Debt [2021-2028, %]



(CFO pre-Working Capital – Dividends) / Debt[2] [2021-2028, %]



Debt / Capitalization[3] [2021-2028, %]



1) CFO: Cash from Operations

2) Dividends are overstated given that RIST financing maintains the allowed capital structure and returns excess equity to shareholders through dividends

3) Debt/Capitalization is unaffected by ROE and increases over time due to an increase in imputed debt

Source: HECO, Moody's, Ulupono Scenario #1 HECO O'ahu in the RIST model (version 5/06)

ATTACHMENT D
REGULATORY INNOVATION SIMULATION TOOL EXHIBITS

Exhibit D-1: Regulatory Innovation Simulation Tool (5/6/2020) (Excel)

Note: Due in part to file size, Ulupono has provided an electronic copy of the version of the RIST Excel spreadsheet used for this Second Proposal Update to the Commission's consultant Rocky Mountain Institute, which has made it available to the Commission and docket parties only. Access or use of the RIST Excel spreadsheet outside of this proceeding is strictly prohibited except by permission of Ulupono. Please contact Ulupono for details.

Exhibit D-2: “RIST Results – Introduction and Key Components”

This exhibit provides a general introduction and overview to the RIST components for modeling Ulupono’s PBR proposals.

RIST Results – Introduction and Key Components

The RIST tested Ulupono's Second Proposal Update with the Ulupono Scenario #1

> Annual Revenue Adjustment (ARA)
  - RPI: 2%, X: 0%, Consumer Dividend: 0.22%

> Proposed Performance Incentive Mechanisms (PIMs)
  - Renewable Portfolio Standard – Accelerated (RPS-A) PIM
  - Greenhouse Gas Emissions Reduction PIM
  - Electrification of Transportation (EoT) PIM
  - Shared Savings Mechanism for PPA and Grid Services/NWA

> Earnings Sharing Mechanism (ESM)
  - 2% deadband
  - Symmetric bands up to 90% sharing

Exhibit D-3: “Recent RIST Updates: May 2020”

This exhibit provides a high-level summary of the edits made to the RIST model since the version submitted to accompany Ulupono’s First Proposal Update filed Jan. 15, 2020. More detailed descriptions have been provided in the Working Group process.

Edits were made in consultation with representatives from Hawaiian Electric in an effort to bring the RIST results closer to Hawaiian Electric’s financial model (UI Planner).

Recent RIST Updates: May 2020

Subject	Update
ECRC and PPAC revenue taxes	ECRC and PPAC revenues are grossed up to include revenue tax. The impact of the ECRC and PPAC revenue tax was removed from Electric Base Revenues.
Revenue Taxes	Revenue taxes are calculated on prior year for Electric Base Revenues (to avoid circular calculations) but current year for other revenues. Previously, the revenue taxes were calculated on prior year revenues.
Pole Revenues	Added high and low forecast in Financial Assumptions tab Rows 56-61, including toggle for switch for high or low revenue forecast, per the filing HECO provided, "Dkt 2018-0075 Joint Pole Redesignation of Exhibit E.pdf"
CWIP	CWIP is estimated using a ratio of CWIP to Capex. The ratio is an input that can be modified by year. We utilized the 2018 ratio of CWIP to Capex of 59% and reduced the value to 50% by 2029. This reflects the theory that the utility will increasingly rely on PPAs and NWAs and will have fewer large capital projects that drive up CWIP compared to Capex.
AFUDC	HECO calculates AFUDC on a monthly basis, but the RIST is an annualized model. As a simplification, AFUDC is calculated using the allowed return on equity and debt multiplied by the CWIP balance at the end of each year.
PIMs	Added two additional PIMs proposed by Ulupono: GHG PIM and grid services/NWA
PIM inflation	Inflation equal to the ARA was added to the reward value for the PIMs
Depreciation	HECO uses a composite rate for book depreciation. We have added a toggle so the user can choose to use depreciation schedules by asset class for historical and future capital or use HECO's composite rate for 2020 for each asset class.

Exhibit D-4: M. Fripp, “Assumptions and Input Data for Ulupono #1 scenario”

This document was submitted with Ulupono’s First Proposal Update filed Jan. 15, 2020, has not been modified, and is included for convenience.

ASSUMPTIONS AND INPUT DATA FOR ULUPONO #1 SCENARIO

Introduction. This document describes how the Switch-Oahu model was configured to choose a long-term generation plan for the "Ulupono #1" scenario for the RIST tool. Switch is an electricity capacity planning model that chooses a cost-minimizing portfolio of generation assets for power systems with large shares of renewable energy. Details are given in Johnson et al. (2018). Switch software and tutorials can be downloaded from http://switch-model.org/. This document describes how Switch was run to create the Ulupono #1 scenario on Dec. 14, 2019. Inputs and outputs for this scenario are available from https://github.com/switch-hawaii/ulupono_scenario_1. The scenario used Switch version 2.0.6.

Geography and calendar. For this scenario, Oahu is modeled as a single zone with adequate internal transmission and no connection to neighbor islands. The generation portfolio is optimized over the period of 2020–2049. Weather and loads during each year are represented by 13 one-day timeseries, with 12 two-hour timesteps on each sample day. Decisions about generator commitment, output, storage and demand response are made during each of these timesteps. These weather days were selected and weighted to match historical conditions in 2007–08 as accurately as possible, including the single most difficult weather day (low wind and sun and high loads).

The model is run in two phases. Initially, the generation portfolio is optimized with new investments allowed in 2020, 2022, 2025, 2030, 2035, 2040 and 2045. After the portfolio is selected, construction of new renewable generation and batteries in each of these periods are spread equally over the years between the preceding period and the current period. The construction plan is then frozen, and Switch is run in production-cost mode to evaluate performance during each year between 2020 and 2045 (2020, 2021, 2022, 2023, etc.). Only data for 2020–38 are used in RIST.

Financial assumptions. All costs input into Switch and reported from Switch are in 2020 real dollars. Switch minimizes costs on an NPV basis, using a 3% discount rate. Capital costs are assumed to be financed with an annual payment over the life of the asset that is constant in real dollars, i.e., escalating with inflation. The cost of capital for this amortization is assumed to be 6% real (~8% nominal). Real-dollar costs are converted to nominal dollars before use in RIST.

Electricity demand. We first calculate "nominal" electricity demand—hourly loads that would be expected if there is no effort to reschedule loads to better times of day—and then allow a portion of the demand to be rescheduled to other hours. These loads are gross loads at the customer premises, including self-supply by distributed generation (DG). For use in RIST, DG is then subtracted to produce net loads. Nominal demand is based on hourly Oahu electricity loads in 2007–08, rescaled to have the same peak and average values as forecast for 2020–45. We currently use forecasts from the 2016 PSIP, increased in all years to make the peak and average forecast for 2018 match actual load in 2018. Peak and average loads for 2016–45 are shown in Figure 1.

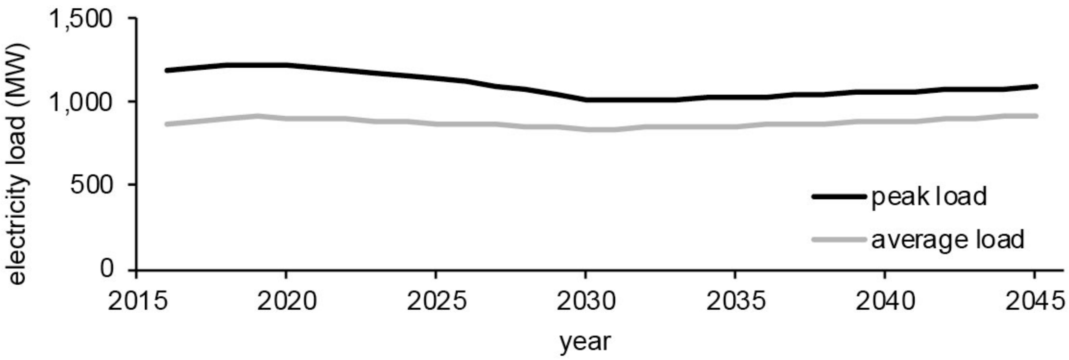


Figure 1. Peak and average nominal load forecasted for Oahu in 2016–45

We assume that 10% of each hour's nominal load can be rescheduled to a different hour of the day, but that the loads in each hour cannot be increased by more than 80%. We assume that this flexible demand cannot be used to provide operating reserves to compensate for forecast errors.

Electric vehicles (EVs). For light-duty vehicles, we use the EV adoption forecast in HECO's Electrification of Transport study, reaching 55% by 2045. We assume the heavy-duty vehicle fleet (buses and trucks) is electrified at the same rate. For light-duty EVs, we use the time-of-day charging pattern that HECO reported for the Electrification of Transport study: 50% following a residential business-as-usual charging profile (provided by HECO 11/20/19) and 50% being charged at optimal times. Charging patterns for heavy-duty vehicles are as follows: 50% of buses charge quasi-continuously while on route, between 6 am and 10 pm; 50% of buses charge off-route at least-cost times between 10 pm and 6 am. Freight vehicles and non-bus diesel passenger vehicles charge at least-cost times while off duty. Off-duty windows for individual vehicles begin at times scattered between 4 and 10 pm and end at times scattered between 5 and 8 am. Energy requirements for vehicle fleet are derived from DBEDT Monthly Energy Trends report and FTA National Transit Database. EVs are assumed to require 3–5 times less energy than gasoline vehicles based on standard test cycles in 2017–18.

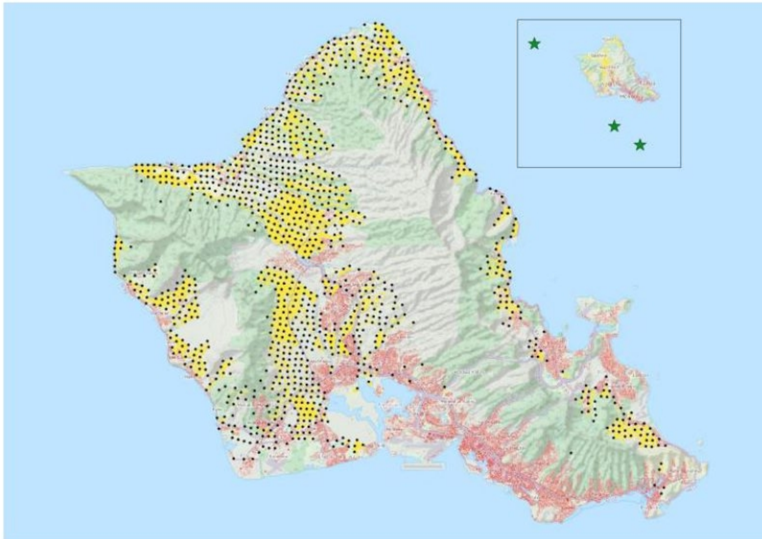


Figure 2. Location of potential renewable resources on Oahu: large solar (gold), rooftop solar (red), onshore wind turbines (black dots) and offshore wind farms (stars in inset)

Onshore wind farm potential and performance. We allow wind development on land that meets all of the following criteria: zoned for "country" or "agricultural" use, slopes of 20% or less, not within 300 meters of edge of allowed zone, not on narrow ridge, turbines at least 600 meters apart. Turbine locations are shown as black dots in Figure 2. Hourly production for each turbine is calculated from gridded data prepared for the OWITS study (Corbus et al. 2010; Manobianco et al. 2010) and earlier 200-meter wind maps(AWS Truewind 2004a; 2004b), using Clipper Liberty 2.5 MW wind turbine model C89, C93 or C99, selected for each site based on its annual average wind speed. Losses are assumed to be 12.53% based on 2013 HECO IRP (HECO 2013).

Offshore wind farm potential and performance. We define a single, generic offshore wind farm, representing the average of potential production at three proposed offshore wind farms near Oahu (BOEM 2016). We use hourly wind speeds for 2007–08 from AWS Truepower (Corbus et al. 2010; Manobianco et al. 2010), for the center of each farm at 100 meter elevation. We calculate hourly power production from these using a generic offshore wind turbine power curve, with the operating range extended to 30 m/s to match the Repower 6M (King, Clifton, and Hodge 2014). We assume 12.53% losses, matching the onshore wind projects. The generic project was assigned a maximum size of 2,400 MW (three times larger than current proposals) to reflect the large resources available. The centers of the three proposed wind farms are shown as stars in the inset map in Figure 2.

Utility scale solar potential and performance. We allow solar development on Oahu land that meets all of the following criteria: zoned for "country" or "agricultural" use; slope below 10%; not designated as Class A agricultural land or "Important Agricultural Lands"; not within 30 meters of the centerline of roads (i.e., roads and urban areas); parcel larger than a 60-meter disk. Land available for large-scale solar is shown as gold in Figure 2. We assume land use of 7.5 acres per MW of PV capacity, which is 15% higher than the 6.5 acres/MW reported by Oahu developers for recent projects. PV systems are modeled as single-axis solar trackers using parameters from the 2019 ATB (NREL 2019), using solar data from NREL's National Solar Radiation Database for 2007–08 (NREL 2016; 2018).

Rooftop solar potential and performance. Rooftop locations are derived from the Google Static Maps API (Google Inc. 2016) and roof orientations and covered area are derived from the Google Sunroof project. We assume that panels on sloped roofs are tilted at 25 degrees and panels on flat roofs are tilted at 5 degrees, matching assumptions in NREL's 2019 ATB (NREL 2019). PV systems are modeled using parameters from the 2019 ATB and solar data from the National Solar Radiation Database for 2007–08.

Rooftop solar power adoption. We use HECO's forecast of distributed PV and storage adoption provided on 11/20/19, shown in Table 1. Switch is not allowed to deviate from this total level of adoption, but it can prioritize more productive areas for development and can exceed 100% of demand on individual premises. Switch does not consider avoided network costs during the optimization stage; these are added in RIST when evaluating the economic impact of the selected portfolio.

Table 1. Adoption of distributed PV and distributed storage in Switch-Oahu

Year	Total DGPV Capacity Online	Total Distributed Storage Online
2020	562 MW	128 MWh
2025	681 MW	264 MWh
2030	823 MW	398 MWh
2035	985 MW	577 MWh
2040	1150 MW	772 MWh
2045	1321 MW	977 MWh

Renewable portfolio standard (RPS). The selected portfolio must meet the following renewable energy targets: 30% in 2020–29, 40% in 2030–39, 70% in 2040–49 and 100% in 2045–49. These targets are calculated as (all renewable production, including utility-scale renewables, biofuels and distributed generation) ÷ (all production, including distributed generation). This is different from the current RPS law, which omits distributed renewable generation from the denominator of this equation. This calculation includes HECO-owned generation, IPP-owned generation and distributed generation.

Operating reserves. The scenario must maintain regulating reserves equal to the lesser of 100% of production from each wind or solar site or 21.3% of the solar equipment rating or 21.6% of the wind equipment rating. These coefficients are based on regression analysis of safe envelopes recommended by GE Energy Consulting (GE Energy 2012, 37–40; GE Energy Consulting 2015, 62; Piwko et al. 2012, 4–6). Switch also maintains upward contingency reserves equal to the largest individual generating unit online each hour and downward contingency reserves equal to 10% of load each hour. Operating reserves can be provided by dedicated contingency or regulating reserve batteries or by maintaining spare capacity in standard batteries or renewable, hydro or thermal generators. We do not allow the system to obtain reserves from flexible demand or EV charging.

Tax credits and subsidies. Federal tax credits are included in the optimization but state tax credits are ignored because they are not a net reduction in total expenditure by Hawaii residents. The rates in effect are shown in Table 2 (DSIRE 2019b; 2019a).

Table 2. Investment tax credits applied in Switch-Oahu

Technology	Year(s)	Investment tax credit
Distributed PV	2020	30%
Utility-scale PV	2020	26%
Utility-scale PV	2025–2045	10%
All other technologies	All other years	0%

Fuel price forecasts. Liquid fuel price forecasts are based on the Brent crude forecast reported by the Energy Information Administration in the Annual Energy Outlook (AEO) 2019. We add a fixed offset to the EIA forecast to obtain a cost for low-sulfur fuel oil (LSFO), diesel or biodiesel delivered to power plants on Oahu. The adjustment factor is –\$0.63/MMBtu for LSFO (lower price than crude oil), +\$4.78/MMBtu for diesel and +\$14.38/MMBtu for biodiesel. These factors were found by comparing Oahu utility prices for these fuels to Brent crude over 2006–18 (2013–18 for biodiesel). Future variable costs for the AES coal plant are based on its power purchase agreement (we are awaiting details from HECO).

Cost of wind and solar projects and batteries. For new wind and solar resources and batteries, we use capital costs (including construction finance and interconnect cost) and O&M costs and project lifetimes from the NREL 2019 ATB (NREL 2019). We adjust capital costs to Hawaii-specific values by applying adders from EIA reports on this subject (EIA 2017; 2016) as recommended by the ATB. These are 35% for wind projects, 64% for large PV, 62% for distributed PV and 28% for batteries. We assume all of these systems (including DG PV) are dispatchable, i.e., they may be limited by available wind or sun, but can produce any amount of power below this limit. We model reserve-only batteries as zero bulk energy storage, but with cost equivalent to 0.5–1 hour of energy storage, as modeled in the PSIP.

We assume an additional cost of \$1000 per MW-km for transmission upgrades required to carry power from utility-scale onshore wind and solar projects to the load center. The distances are calculated from the center of each cluster to the population-weighted center of Oahu. This produces upgrade costs in the range of \$1,000–36,000 per MW of capacity from these technologies. Tie-line costs for offshore wind are included in the NREL ATB costs reported in section **Error! Reference source not found.**, and we assume these tie lines connect to a strong point on the transmission network, requiring no additional upgrades. We assume that distributed solar, batteries and thermal power plants use existing transmission capacity, so they also don't require transmission upgrades to carry power to market.

Table 3. Capital cost, O&M and project lifetime for wind farms, solar arrays and batteries installed in 2020 or 2045

Vintage	Technology	Capital cost (2020$ /kW)	Storage capital cost (2020$ /kWh)	Fixed O&M (2020$ /kW-yr)	Asset life (years)
2020	Onshore wind	$2,188	–	$45	30
	Offshore wind	$7,105	–	$85	30
	Utility-scale PV	$1,879	–	$13	30
	Sloped-roof PV	$4,317	–	$21	30
	Flat-roof PV	$2,790	–	$13	30
	Batteries	$785	$226	$34	15
2045	Onshore wind	$1,500	–	$37	30
	Offshore wind	$3,083	–	$42	30
	Utility-scale PV	$1,261	–	$9	30
	Sloped-roof PV	$1,863	–	$9	30
	Flat-roof PV	$1,858	–	$11	30
	Batteries	$402	$116	$17	15

Pumped-storage hydro. We model a potential pumped-storage hydro project at Lake Wilson with these parameters: maximum size of 150 MW, up to 12 hours of storage, 10 MW available from water inflow, round-trip efficiency of 77%, capital cost of $3,033/kW, fixed O&M of $45.50/kW-year and lifetime of 50 years. These parameters are based on personal communication from John Wehrheim of Pacific Hydro.

New thermal power plants. We do not allow development of new thermal power plants in this scenario.

Hydrogen storage. Switch is able to model production and consumption of hydrogen in stationary facilities to provide seasonal and diurnal energy storage. However, we do not allow hydrogen storage in this scenario because it is a pre-commercial technology and because future costs are uncertain. In previous modeling with Switch, hydrogen generally displaces a portion of biofuels and does not have a strong effect on overall costs.

Existing HECO thermal power plants. We use heat-rate curves, fuel type and min/max load for HECO power plants from Appendix A of the Hawaii Solar Integration Study (GE Energy 2012). We use fixed and variable O&M for the equivalent technology from the Assumptions to the Annual Outlook for the year the generating unit was built, converted to 2020 dollars (EIA 1996; 2009; 2013). The earliest edition of the Annual Energy Outlook currently available is 1996, so we used those costs for plants built before 1996. Generating units are assumed to retire on the schedule shown in the 2016 PSIP: Waiau 3–5 in 2020; Waiau 6–8 and Kahe 1–4 in 2022; Kahe 5–6 in 2045; and the rest after 2050: Waiau 9–10, CIP CT, Airport DG and Schofield. All these plants are assumed to be able to use biodiesel in addition to their primary fuel.

Power purchase agreements (PPAs) with existing thermal power plants. PPA costs are modeled as a capacity payment and an energy payment. The capacity payment is based on amortized capital cost and fixed O&M costs and the energy payment is based on variable O&M costs and a fuel cost passthrough. All the terms other than fuel are constant in real dollars. For Kalaeloa and AES, we use construction and O&M costs for combined cycle and pulverized coal plants in the Assumptions for the Annual Energy Outlook 1996 (EIA 1996). When these terms are used with 2018 production data, they result in energy charges that are within 2.2% of the energy charges that HECO reported to the PUC in 2018 (Hawaii PUC 2018, 66). HECO does not report capacity payments to the PUC, so we are not able to verify those. We assume the AES coal plant retires by 2022 and Kalaealoa retires in 2050 or later.

For the H-POWER plant we assign a variable O&M cost that is equal to the average energy charge that HECO reported to the PUC in 2018 (Hawaii PUC 2018, 66). We assign a capital cost and fixed O&M make the total capacity payment equal the value that HECO reported on 12/12/2019 in response to an informal information request ($17,685,360/year). We assume the H-POWER plant runs at 42.8 MW at all times (average production in 2015) and retires after 2050. It is assumed to be RPS-eligible.

The Tesoro Hawaii and Hawaii Cogen plants are omitted from this scenario but may be added at a later date.

Kalaeloa plant operating rules. The Kalaeloa combined-cycle power plant is operated by an independent power producer. In addition to producing power, it also sells steam to the Par Hawaii refinery, the largest of two on Oahu. Due to this arrangement, the Kalaeloa plant has a contract with HECO under which it produces at least 75 MW of power whenever possible. We assume this requirement is relaxed if the vehicle fleet exceeds 75% electric or the RPS exceeds 75% (i.e., in 2045 and later).

Maintenance outages. HECO-owned thermal power plants and AES and Kalaeloa are placed on maintenance outage 2–36% of the time, using reference schedules from GE Energy Consulting, as described in Fripp (2018).

Predetermined utility-scale generation. We assume all generation projects listed in Oahu on the 2018 EIA Form 860 are currently in service. We also assume that renewable projects and storage listed as completed, under construction or approved by regulators in 2019–2022 on HECO's Renewable Project Status Board (HECO 2019) enter service on the dates specified there: 24 MW onshore wind in 2020 (Na Pua Makani), 8.5 MW of utility-scale solar in 2020 (feed-in tariff projects) and 139.5 MW of utility-scale solar with 4-hour batteries in 2021 (results of RFP Phase 1 in 2018-19).

We assume 4.990 MW of CBRE Phase 1 solar enters service in 2020 and 150 MW of CBRE Phase 2 solar enters service in 2022. The 150 MW for CBRE Phase 2 is a "best guess" based on recent discussions of a 235 MW target for all islands in the CBRE docket (Joint Parties 2019). HECO commented on 11/19/19 that "The Companies are only able to assume what is included in the current PUC D&O framework of 64MW, although the Companies have recommended that the program be large enough to attract larger developers and proposed increasing the capacity to 235MW (either solar or wind) over 5 years and revisit capacity availability as part of the IGP process."

We include 560 MW of additional utility-scale solar in 2022, representing RFP Phase 2 acquisitions. This matches the "Up to 1,300,000 MWh annually" listed for Oahu in 2022–25 on HECO's Renewable Project Status Board (HECO 2019). We allow Switch to select the optimal amount of battery storage to complement this resource.

Although CBRE Phase 2 and RFP Phase 2 allow for both solar and wind power, we assume the additions will be only solar power. If wind power were added in this time frame, it would likely decrease the amount of wind selected by Switch for later years, and possibly cause Switch to add more solar later.

The projects listed above are the only generating capacity that Switch is allowed to add in 2020–22. We also assume that renewable projects and batteries built in 2022 or earlier are recommissioned at equal size when they reach retirement age. Switch optimizes the selection of all other assets after 2022 to minimize costs.

Reconstruction costs. Projects that reach their retirement age and are then recommissioned are assumed to require the same annual capital recovery (amortization) as new greenfield projects built on the same date. This somewhat inflates the cost of projects reconstructed during the later years of the scenario. This only affects PV and wind built in 2015 or earlier and replaced after 30 years, or batteries built in 2020-2030 and replaced after 15 years.

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BEFORE THE PUBLIC UTILITIES COMMISSION OF THE

STATE OF HAWAII

In the Matter of PUBLIC UTILITIES COMMISSION Instituting a Proceeding to Investigate Performance-Based Regulation.	DOCKET NO. 2018-0088

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